Inspection Practices for Atmospheric and Low-Pressure Storage Tanks

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1 Scope

This document provides useful information and recommended practices for the maintenance and inspection of atmospheric and low-pressure storage tanks. While these maintenance and inspection guidelines may apply to other types of tanks, these practices are intended primarily for existing tanks which were constructed to one of the following four standards: API 12A, API 12C, API 620, or API 650. This document addresses the following:

a) descriptions and illustrations of the various types of storage tanks;

b) new tank construction standards;

c) maintenance practices;

d) reasons for inspection;

e) causes of deterioration;

f) frequency of inspection;

g) methods of inspection;

h) inspection of repairs;

i) preparation of records and reports;

j) safe and efficient operation;

k) leak prevention methods.

This Recommended Practice (RP) is intended to supplement API 653, which provides minimum requirements for maintaining the integrity of storage tanks after they have been placed in service.

2 Normative References

2.1 Codes, Standards, and Related Publications

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 12A, *Specification for Oil Storage Tanks with Riveted Shells* (withdrawn)

API Specification 12B, *Bolted Tanks for Storage of Production Liquids*

API Specification 12C, *API Specification for Welded Oil Storage Tanks* (withdrawn)

API Specification 12D, *Field Welded Tanks for Storage of Production Liquids*

API Specification 12E, *Specification for Wooden Production Tanks* (withdrawn)

API Specification 12F, *Shop Welded Tanks for Storage of Production Liquids*

API Recommended Practice 12R1, *Recommended Practice for Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service*

API Publication 306, *An Engineering Assessment of Volumetric Methods of Leak Detection in Aboveground Storage Tanks*

API Publication 307, *An Engineering Assessment of Acoustic Methods of Leak Detection in Aboveground Storage Tanks*

API Publication 315, *Assessment of Tankfield Dike Lining Materials and Methods*

API Publication 322, *An Engineering Evaluation of Acoustic Methods of Leak Detection in Aboveground Storage Tanks*

API Publication 323, *An Engineering Evaluation of Volumetric Methods of Leak Detection in Aboveground Storage Tanks*

API Publication 325, *An Evaluation of a Methodology for the Detection of Leaks in Aboveground Storage Tanks*

API Publication 334, *A Guide to Leak Detection for Aboveground Storage Tanks*

API Publication 340, *Liquid Release Prevention and Detection Measures for Aboveground Storage Facilities*

API Publication 341*, A Survey of Diked-Area Liner Use at Aboveground Storage Tank Facilities*

API Recommended Practice *545, Recommended Practice for Lightning Protection of Above Ground Storage Tanks for Flammable or Combustible Liquids*

API 570, Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems

API Recommended Practice *571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 572, *Inspection of Pressure Vessels*

API Recommended Practice 576, *Inspection of Pressure-Relieving Devices*

API Recommended Practice 579, *Fitness-for-Service*

API Recommended Practice 580, *Risk-Based Inspection*

API Publication 581, *Risk-Based Inspection—Base Resource Document*

API Standard 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*

API Standard 625, *Tank Systems Storing Refrigerated, Liquefied Gas*

API Standard 650, *Welded Steel Tanks for Oil Storage*

API Recommended Practice 651, *Cathodic Protection of Aboveground Petroleum Storage Tanks*

API Recommended Practice 652, *Lining of Aboveground Petroleum Storage Tank Bottoms*

API Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*

API Standard 2000, *Venting Atmospheric and Low-Pressure Storage Tanks: Nonrefrigerated and Refrigerated*

API Recommended Practice 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*

API Standard 2015, *Requirements for Safe Entry and Cleaning of Petroleum Storage Tanks*

API Recommended Practice 2016, *Guidelines and Procedures for Entering and Cleaning Petroleum Storage Tanks*

API Standard 2610, *Design, Construction, Operation, Maintenance & Inspection of Terminal and Tank Facilities*

AISC [1], *Steel Construction Manual*

ASME *Boiler and Pressure Vessel Code* [2], Section V, *"Nondestructive Examination"*

ASME *Boiler and Pressure Vessel Code*, Section VIII, "*Rules for the Construction of Pressure Vessels"*

ASME *Boiler and Pressure Vessel Code*, Section IX, *"Welding and Brazing Qualifications"*

ASNT [3], SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing*

ASNT, CP 189, *Standard for Qualification and Certification of Non-destructive Testing Personnel*

ASTM [4], D3359, *Standard Test Methods for Measuring Adhesion by Tape Test*

EEMUA 159 [5], *Users' Guide to the Inspection, Maintenance and Repair of Aboveground Vertical Cylindrical Steel Storage Tanks—Volume 1*

NFPA 30 [6], *Flammable and Combustible Liquids Code*

OSHA [7], 29 *CFR* Part 1910.23*, Guarding Floor and Wall Openings and Holes*

OSHA 29 *CFR* Part 1910.24*, Fixed Industrial Stairs*

OSHA 29 *CFR* Part 1910.27*, Fixed Ladders*

OSHA 29 *CFR* Part 1910.146*, Permit-Required Confined Spaces*

UL 142 [8], *Steel Aboveground Tanks for Flammable and Combustible Liquids*

[1] American Institute of Steel Construction, One East Wacker Drive, Suite 700, Chicago, Illinois 60601, www.aisc.org.
[2] ASME International, Three Park Avenue, New York, New York 10016-5990, www.asme.org.
[3] American Society for Nondestructive Testing, 1711 Arlingate Lane, P.O. Box 28518, Columbus, Ohio 43228, www.asnt.org.
[4] ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.
[5] Engineering Equipment & Materials Users' Association, 63 Mark Lane, LONDON, EC3R 7NQ, www.eemua.co.uk.
[6] National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.
[7] U.S. Department of Labor, Occupational Safety and Health Administration, 200 Constitution Avenue, NW, Washington, DC 20210, www.osha.gov.
[8] Underwriters Laboratories, 333 Pfingsten Road, North Brook, Illinois 60062-2096, www.ul.com.

2.2 Other References

The following codes and standards are not cited in the text of this RP. Familiarity with these documents is suggested as they provide additional information pertaining to the inspection and repair of aboveground storage tanks.

OSHA 29 *CFR* Part 1910.106, *Flammable and Combustible Liquids*

STI SP001 [9], *Standards for Inspection of In-Service Shop Fabricated Aboveground Tanks for Storage of Combustible and Flammable Liquids*

3 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1
alteration
Any work on a tank involving cutting, burning, welding, or heating operations that changes the physical dimensions and/or configuration of a tank. Examples of alterations include:

a) the addition of a manway or nozzle exceeding 12 in. NPS (nominal pipe size),

b) an increase or decrease in tank shell height.

3.2
applicable standard
The original standard of construction, such as API standards or specifications or Underwriter Laboratories (UL) standards, unless the original standard of construction has been superseded or withdrawn from publication; in this event, applicable standard means the current edition of the appropriate standard. See API 653, Annex A for background on editions of API welded storage tank standards.

3.3
atmospheric pressure
When referring to (vertical) tanks, the term "atmospheric pressure" usually means tanks designed to API 650, although API 620 uses the term atmospheric pressure to describe tanks designed to withstand an internal pressure not exceeding the weight of the roof plates. API 650 also provides for rules to design tanks for "higher internal pressure" up to 2.5 lbf/in.^{2} (18 kPa). API 653 uses the generic meaning for atmospheric pressure to describe tanks designed to withstand an internal pressure up to, but not exceeding 2.5 lbf/in.^{2} (18 kPa) gauge.

3.4
authorized inspection agency
The inspection organization having jurisdiction for a given aboveground storage tank. It can be one of the following.

a) The inspection organization of an insurance company which is licensed or registered to and does write aboveground storage tank insurance.

b) An owner or operator of one or more aboveground storage tank(s) who maintains an inspection organization for activities relating only to his equipment and not for aboveground storage tanks intended for sale or resale.

c) An independent organization or individual under contract to and under the direction of an owner or operator and recognized or otherwise not prohibited by the jurisdiction in which the aboveground storage tank is operated. The owner or operator's inspection program should provide the controls necessary for use by authorized inspectors contracted to inspect aboveground storage tanks.

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[9] Steel Tank Institute, 570 Oakwood Road, Lake Zurich, Illinois 60047, www.steeltank.com.

3.5
authorized inspector
An employee of an authorized inspection agency that is certified as an aboveground storage tank inspector per API 653, Annex D.

3.6
bottom-side
The exterior surface of the tank bottom, usually used when describing corrosion. Other terms with the same meaning are "under-side" or "soil-side."

3.7
change-in-service
A change from previous operating conditions involving different properties of the stored product such as specific gravity or corrosivity and/or different service conditions of temperature and/or pressure.

3.8
examiner
A person who assists the API authorized tank inspector by performing specific non-destructive examination (NDE) on the tank but does not evaluate the results of those examinations in accordance with API 653 or this recommended practice, unless specifically trained and authorized to do so by the owner or user. The examiner does not need to be certified in accordance with API 653 nor needs to be an employee of the owner or user, but should be trained and competent in the applicable procedures in which the examiner is involved. In some cases, the examiner may be required to hold other certifications as necessary to satisfy owner or user requirements. Examples of other certification that may be required are American Society for Non-Destructive Testing SNT-TC-1A or CP189, or American Welding Society Welding Inspector Certification. The examiner's employer should maintain certification records of the examiners employed, including dates and results of personnel qualifications and should make them available to the API Authorized Inspector.

3.9
inspector
An authorized inspector and an employee of an authorized inspection agency who is qualified and certified to perform tank inspections under this standard.

3.10
magnetic flux leakage
MFL
An electromagnetic scanning technology for tank bottoms also known as MFE (magnetic flux exclusion).

3.11
minimum acceptable thickness
The lowest thickness at which a tank component should operate, as determined by the parameters in the applicable tank design standard (such as API 650, API 653, etc.), the fitness for service principles in API 579, or other appropriate engineering analysis.

3.12
product-side
The interior surface of a tank bottom, usually used when describing corrosion. Other terms with the same meaning are "top-side" or "product-side."

3.13
owner/operator
The legal entity having control of and/or responsibility for the operation and maintenance of an existing storage tank.

3.14
reconstruction
The work necessary to re-assemble a tank that has been dismantled and relocated to a new site.

3.15
reconstruction organization
The organization having assigned responsibility by the owner/operator to design and/or reconstruct a tank.

3.16
repair
Any work necessary to maintain or restore a tank to a condition suitable for safe operation. Typical examples of repairs include:

a) removal and replacement of material (such as roof, shell, or bottom material, including weld metal) to maintain tank integrity,

b) re-leveling and/or jacking of a tank shell, bottom, or roof,

c) addition of reinforcing plates to existing shell penetrations,

d) repair of flaws, such as tears or gouges, by grinding and/or gouging followed by welding.

3.17
shell capacity
The capacity that the tank can hold based on the design liquid level (see API 650).

3.18
soil-side
See definition for **bottom-side**.

3.19
storage tank engineer
One or more persons or organizations acceptable to the owner or user who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics affecting the integrity and reliability of tank components and systems. The tank engineering, by consulting with appropriate specialists, should be regarded as a composite of all entities necessary to properly address technical requirements and engineering evaluations.

3.20
tank specialist
Someone experienced in the design and construction of tanks per API 620 and/or API 650, and the inspection and repair of tanks per API 653.

3.21
top-side
See definition for product-side.

4 Types of Storage Tanks

4.1 General

Storage tanks are used to store fluids such as crude oil, intermediate and refined products, gas, chemicals, waste products, water, and water/product mixtures. Important factors such as the volatility of the stored fluid and the desired

storage pressure and temperature result in tanks being built of various types, sizes, and materials of construction. In this document, only atmospheric and low-pressure storage tanks are considered. Guidelines for inspection of pressure vessels operating at pressures greater than 15 lbf/in^2 (103 kPa) gauge are covered in API 572.

4.1.1 Storage Tanks with Linings and/or Cathodic Protection

Where internal corrosion is experienced or expected, tanks can be lined with a variety of corrosion resistant materials such as coatings of epoxy or vinyl, fiberglass, poured or sprayed concrete, alloy steel, aluminum, rubber, lead, synthetics such as HDPE or hypalon, and glass.

See API 652 for provisions for the application of tank bottom linings to both existing and new storage tanks.

Cathodic protection systems are often provided for control of external bottom corrosion and, combined with internal linings, may also be used to protect tank bottoms internally. See API 651 for design, maintenance, and monitoring recommendations for such systems.

4.1.2 Storage Tanks with Leak Detection Systems

Unprotected storage tank bottoms may leak because of top-side or under-side corrosion or both. API 650, Appendix I, provides design guidelines for leak detection and subgrade protection. Reference also API 306, API 307, API 315, API 322, API 323, API 325, API 334, API 340, and API 341 for additional information on leak detection systems for storage tanks and dike containment areas.

4.1.3 Storage Tanks with Auxiliary Equipment

Most storage tanks are provided with some of the following auxiliary equipment such as liquid-level gauges, high-and low-level alarms and other overfill protection systems, pressure-relieving devices, vacuum venting devices, emergency vents, gauging hatches, roof drain systems, flame arrestors, fire protection systems and mixing devices.

Stairways, ladders, platforms, handrails, piping connections and valves, manholes, electric grounding connections (as required), and cathodic protection systems are considered examples of storage tank auxiliary equipment.

Insulation may also be present to maintain product temperature. Insulation can vary from externally jacketed panel systems to sprayed-on foam systems to loose-fill systems in double-wall tank construction.

Inspection and failure of auxiliary equipment are covered in 5.5.

4.2 Atmospheric Storage Tanks

4.2.1 Construction, Materials, and Design Standards

Atmospheric storage tanks are designed to operate with internal gas and vapor spaces at pressures close to atmospheric pressure. Such tanks are usually constructed of carbon steel, alloy steel, aluminum or other metals, depending on service. Additionally, some tanks are constructed of non-metallic materials such as reinforced concrete, reinforced thermoset plastics, and wood. Some wooden tanks constructed to API 12E are still in service. Atmospheric storage tanks are generally welded. Some riveted tanks constructed to API 12A and some bolted tanks constructed to API 12B can also be found still in service. Information for the construction of atmospheric storage tanks is given in API 12A (withdrawn), API 12B, API 12C (the predecessor to API 650 and now withdrawn), API 12D, API 12E (withdrawn), API 12F, API 650, API 620 and API 2000. API 625 covers the selection, design and construction of tank systems for refrigerated liquefied gas storage on land. API 653 provides information pertaining to requirements for inspection, repair, and reconstruction of aboveground storage tanks.

4.2.2 Use of Atmospheric Storage Tanks

Atmospheric storage tanks in the petroleum industry are normally used for fluids having a true vapor pressure that is less than atmospheric pressure. Vapor pressure is the pressure on the surface of a confined liquid caused by the vapors of that liquid. Vapor pressure increases with increasing temperature. Crude oil, heavy oils, gas oils, furnace oils, naphtha, gasoline, and non-volatile chemicals are usually stored in atmospheric storage tanks. Many of these tanks are protected by pressure-vacuum vents that limit the pressure difference between the tank vapor space and the outside atmosphere to a few ounces per square inch.

Non-petroleum industry uses of atmospheric tanks include storage of a variety of chemicals and other substances operated in closed-loop systems not vented to atmosphere and with pressure control and relief devices as required. These tanks may be designed and operated as low-pressure storage tanks per API 620. See 4.3 for additional information on tanks operated at low pressure.

Additional uses for atmospheric storage tanks can include liquid (both hydrocarbon and non-hydrocarbon) storage in horizontal vessels, storage of process liquids or granular solids in skirt-supported or column-supported tanks with elevated cone bottoms (non-flat bottom) and process water/liquids in open-top tanks.

4.2.3 Types of Atmospheric Storage Tank Roofs

The most common type of atmospheric storage tank is the fixed cone roof tank (see Figure 1). Fixed cone roof tanks may typically be up to 300 ft (91.5 m) in diameter and 64 ft (19.5 m) in height (although larger diameter tanks have been built, mostly outside the U.S.). These roofs are normally supported by internal structural rafters, girders and columns but can be fully self-supporting in smaller diameters (typically, 60 ft [18.3 m] diameter or less). Geodesic domes may be applied to any diameter tank without the need for internal supporting columns.

The umbrella roof tank (shown in Figure 2) and the geodesic dome roof tank (shown in Figure 3) are variations of the fixed roof tank. The umbrella roof has radially-arched segmental plates with integral framing support members (usually without internal support columns). The aluminum dome utilizes the geometric properties of the geodesic design and tubing members covered by aluminum sheeting for strength. In the steel dome roof tank shown in Figure 4, the roof plates are usually formed with curved segments joined to be self-supporting.

Figure 1—Cone Roof Tank

Figure 2—Umbrella Roof Tank

The floating-roof tank is another common type of atmospheric storage tank. The floating-roof tank is designed to minimize filling and breathing losses by eliminating or minimizing the vapor space above the stored liquid. The shell and bottom of this type of tank are similar to those of the fixed roof tanks, but in this case, the roof is designed to float on the surface of the stored liquid. Older styles of floating roofs include single steel deck details without annular pontoons as shown in Figure 5. This external floating roof type is not longer permitted under API 650, Appendix C. Such roofs have no reserve buoyancy and are susceptible to sinking in service.

Figure 3—Geodesic Dome Roof Tank

Figure 4—Self-supporting Dome Roof Tank

Figure 5—Pan Type Floating-roof Tank

Annular-pontoon and double-deck roofs are shown in Figure 6 and Figure 7, respectively. Some floating-roof tanks have fixed aluminum geodesic dome roofs installed on top of the tank shell to reduce product vapor loss or to eliminate the need to drain rainwater from the roof. These are considered internal floating roofs.

Cross-sectional sketches showing important features of floating roofs are shown in Figure 8. Floating-roof sealing systems are used to seal the space between the tank wall and the floating roof, typically with a mechanical seal. This type of seal consists of a shoe which is a plate that is pressed against the tank wall by springs (or by counter-weights in older designs) or other tensioning system, with a flexible vapor membrane attached between the shoe and the floating-roof outer rim. Typical examples of this type of floating-roof seal are shown in Figure 9, Figure 10, and Figure 11. One alternative seal detail occasionally still found in existing tanks is the tube seal shown in Figure 12. These tubes are filled with solid foam, liquid, or air. Figure 13 and Figure 14 illustrate various pontoon roofs and seal details.

Another type of tank has both a fixed roof and an internal floating roof. The fixed roof is usually a supported cone or dome (of steel or aluminum). The internal floating roof can be constructed of steel, aluminum, or other material, as shown in Figure 14. Such tanks are usually built to alleviate weather-related concerns about the flotation of an external floating roof, to reduce vapor emissions, or to prevent product contamination. An existing fixed roof tank often

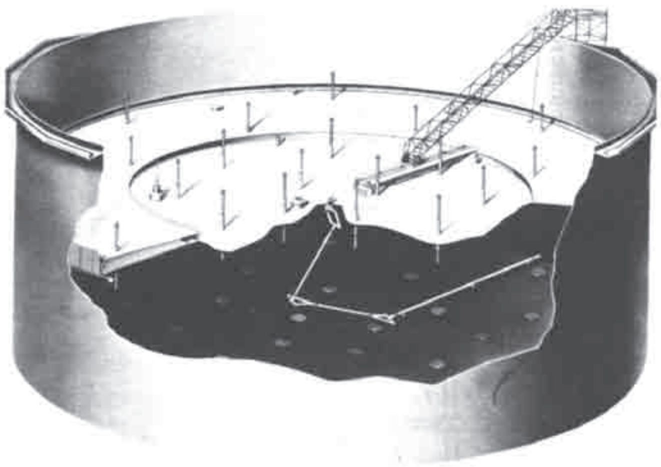


Figure 6—Annular-pontoon Floating-roof Tank

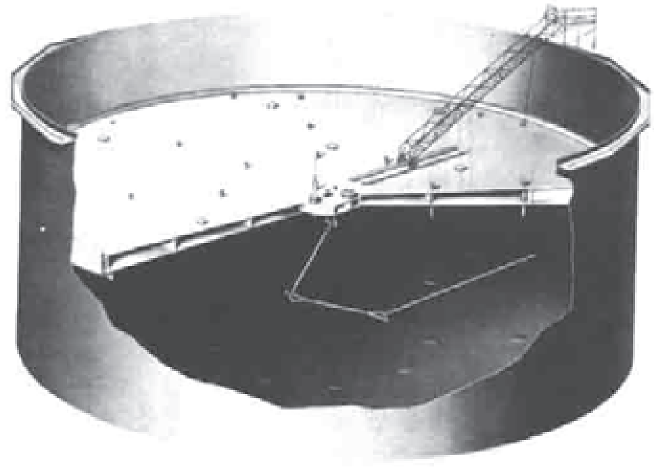


Figure 7—Double-deck Floating-roof Tank

can be modified by the installation of an internal floating roof. Cone roofs with an internal floating roof supported by cables suspended from the fixed cone roof are a newer design that is being used (see Figure 13).

API 650, Appendix H, classifies internal floating roofs into the following types.

a) Metallic internal floating roofs[10,11,12] have a peripheral rim above the liquid for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel. See Figure 15.

b) Metallic open top bulk-headed internal floating roofs[11,12] have peripheral open-top bulk-headed compartments for buoyancy. Distributed open-top bulk-headed compartments shall be used as required. These roofs are in full contact with the liquid surface and are typically constructed of steel.

c) Metallic pontoon internal floating roofs have peripheral closed-top bulk-headed compartments for buoyancy. Distributed closed-top bulk-headed compartments shall be used as required. These roofs are in full contact with the liquid surface and are typically constructed of steel.

d) Metallic double-deck internal floating roofs have continuous closed top and bottom decks that contain bulk-headed compartments for buoyancy. These roofs are in full contact with the liquid surface and are typically constructed of steel.

e) Metallic internal floating roofs on floats have their deck above the liquid, supported by closed pontoon compartments for buoyancy. These roof decks are not in full contact with the liquid surface and are typically constructed of aluminum alloys or stainless steel.

Other less commonly used atmospheric storage tank roof details include the lifter-type roof and the breather-type roof. Lifter-type roofs prevent vapor losses from the tank by means of liquid or dry seals. Liquid-seal lifter roofs have a skirt on the roof edge which fits into a trough filled with liquid. Dry-seal lifter roofs have a flexible membrane connected

10 The purchaser is cautioned that this design does not have multiple floatation compartments necessary to meet the requirements of H.4.2.1.3 in API 650.

11 These designs contain no closed buoyancy compartments, and are subject to flooding during sloshing or during application of fire-fighting foam/water solution. Also, without bracing of the rim being provided by the pontoon top plate, design to resist buckling of the rim must be evaluated.

12 If the floating roof is: a) a metallic pan roof with or without bulkheads, or b) a non-metallic roof with or without closed buoyancy compartments, then the tank is considered a fixed-roof tank (i.e. having no internal floating roof) for the requirements of NFPA 30. See NFPA 30 for spacing restrictions on floating roof tanks.

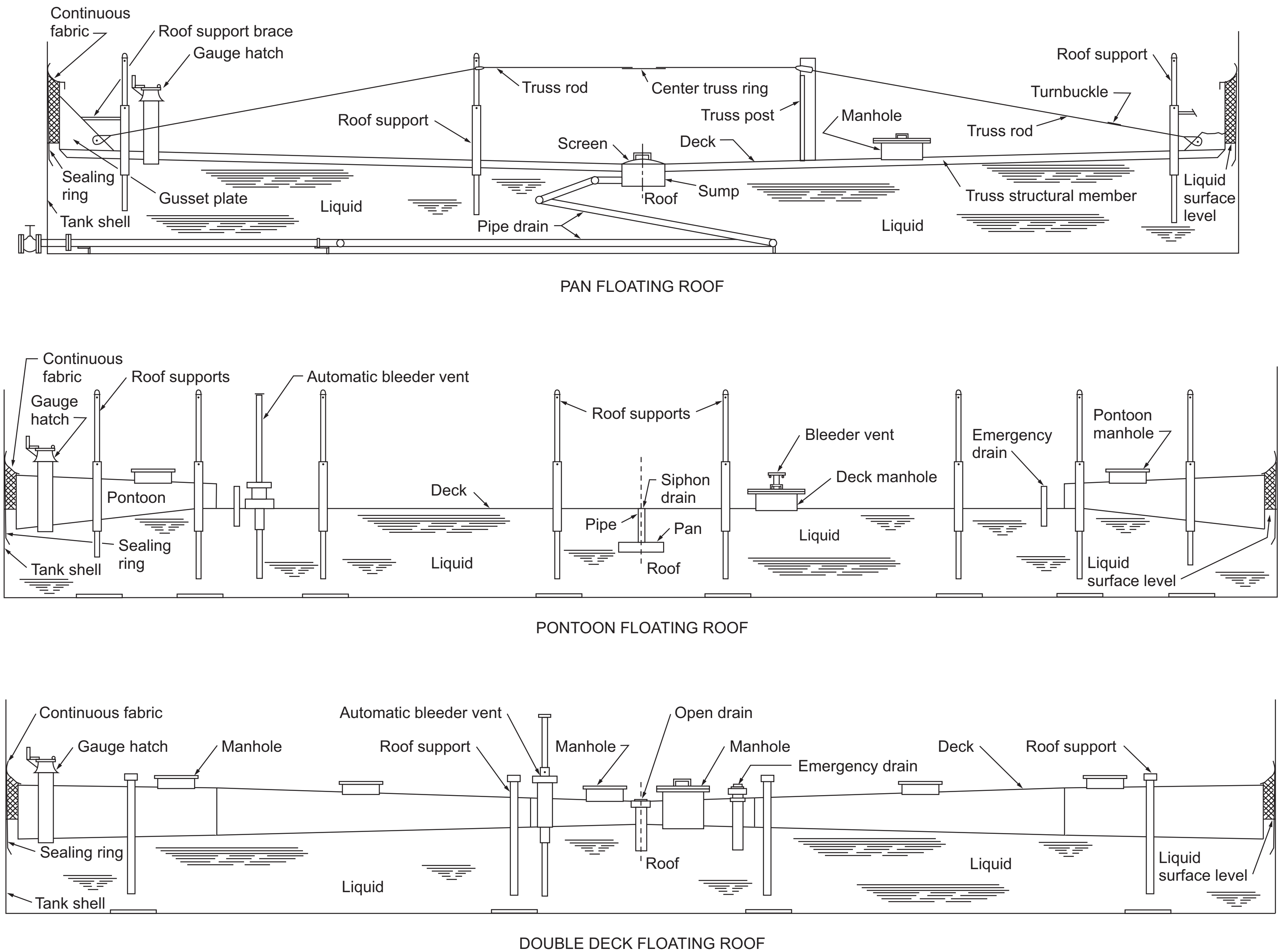
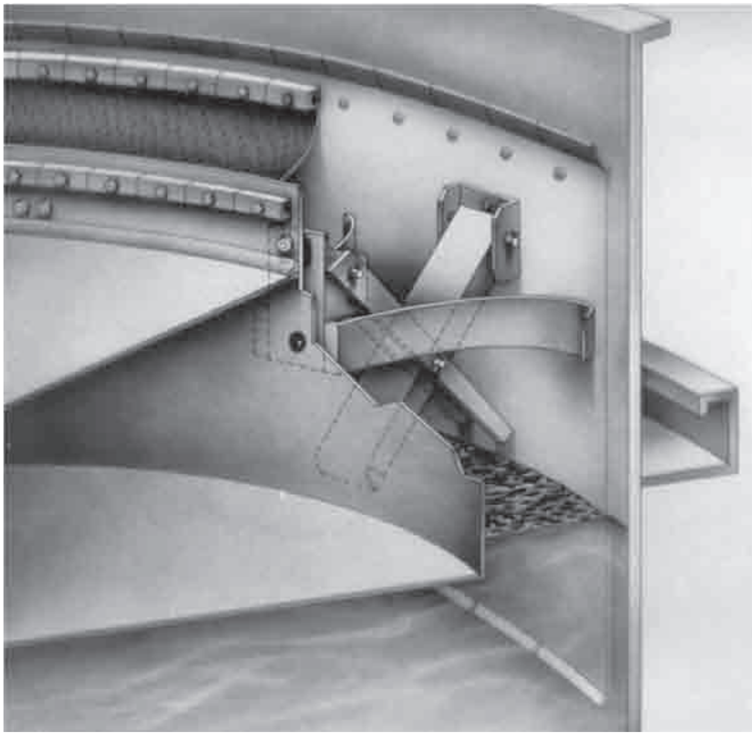


Figure 8—Cross-section Sketches of Floating-roof Tanks Showing the Most Important Features



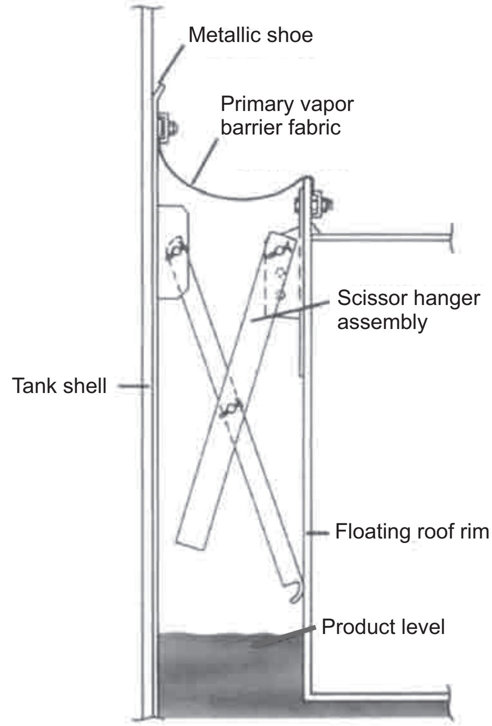


Figure 9—Floating-roof Shoe Seal

to the tank wall and a skirt on the roof edge. In these two lifter-type roofs the roof is free to move up and down within limits as the tank is filled and emptied or when a change in temperature causes vaporization of the stored product. These types of lifter-roof tanks are less commonly found in service today than in the past.

In the breather-type roof, a number of methods are used to provide expansion space for vapors without using a loose external roof. The plain breather-type tank (shown in Figure 16) has a flat roof that is essentially a flexible steel membrane which is able to move up and down within rather narrow limits. The balloon-type roof (shown in Figure 18) is a modification of the plain breather-type roof that is capable of a greater change of volume. A tank with a vapor-dome roof (shown in Figure 17 and Figure 19) uses an added fixed dome with a flexible membrane attached to the walls that is free to move up and down. This type of vapor roof may be designed to provide for any desired change in volume. Vapor recovery systems may use this type of tank.

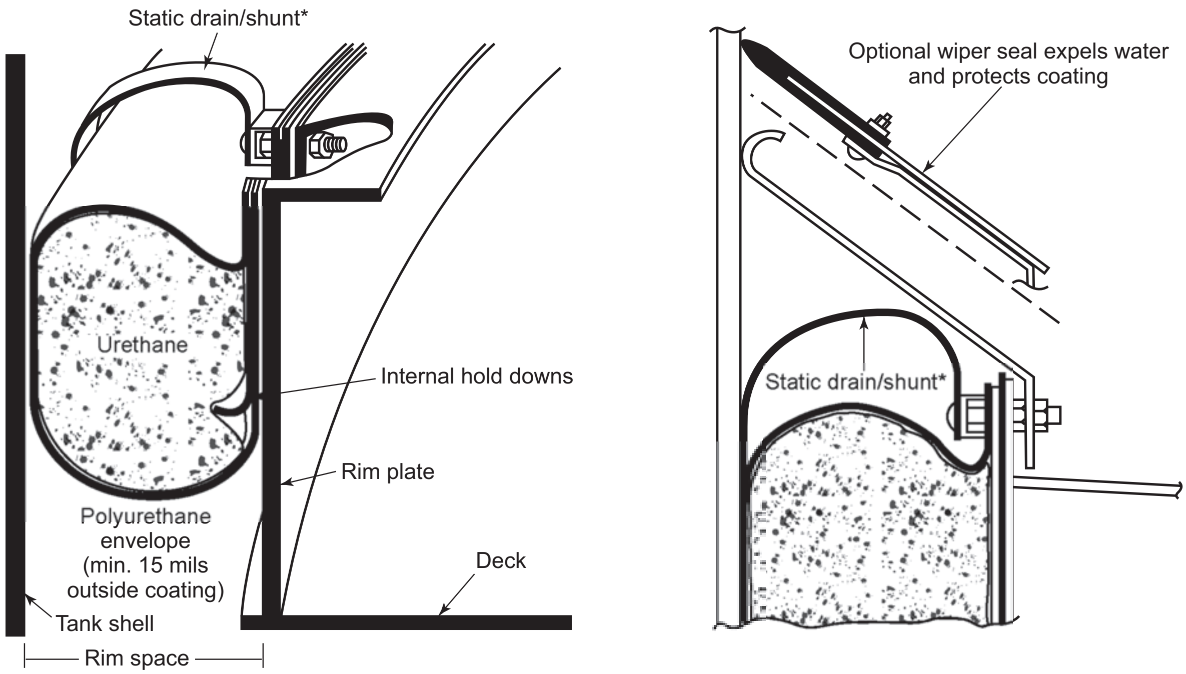
Vapor recovery systems can be provided on several types of tanks such as a fixed cone roof like Figure 1, umbrella roofs like Figure 2 and vapor dome roofs like Figure 17. Adjustment in relieve value settings will be required to accommodate the operating parameters for the vapor recovery system.

Small cylindrical tanks, usually with flat heads or end plates, can be used for the storage of small quantities of liquids at atmospheric pressure. These tanks can be placed in either the vertical position or the horizontal position. A typical horizontal tank is shown in Figure 20.

4.3 Low-Pressure Storage Tanks

4.3.1 Construction, Materials, and Design Standards

Low-pressure storage tanks are those designed to operate with pressures in their gas or vapor spaces exceeding the 2.5 lbf/in.^{2} (18 kPa) gauge permissible in API 650, but not exceeding the 15 lbf/in.^{2} (103 kPa) gauge maximum limitation of API 620. These tanks are generally constructed of carbon or alloy steel and are usually welded, although



Cross-Section Foam Seal for Steel Floating Roof

Cross-Section Foam Seal in Hand Floating Roof with Standard Weather Shield for Longer Seal Life

*This location for static drains or shunts has been used in the pictrure. However, API 545 no longer allows for shunts to be installed in this location due to elevated potential for static electiricity arcing. Regardless, this orientation may be seen by inspectors while conducting inspection of tanks.

Figure 10—Floating-roof Log Seal

riveted tanks in low-pressure service are still found. Rules for the design and construction of large, welded, low-pressure storage tanks are included in API 620. Venting requirements are covered in API 2000.

API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, addresses tank systems design for storing refrigerated liquefied gas. A tank system consists of one or more containers together with various accessories, appurtenances and insulation. The metal storage containers themselves are addressed by API 620, Appendix R for steel containers for refrigerated products from 40 °F (4 °C) to –60 °F (–51 °C), by API 620, Appendix Q for steel containers for –60 °F (–51 °C) to –325 °F (–198 °C). ACI 376, *Code Requirements for Design and Construction of Concrete Structures for the Containment of Refrigerated Liquefied Gas*, addresses concrete containers for 40 °F (4 °C) to –270 °F (–168 °C).

4.3.2 Use of Low-pressure Storage Tanks

Low-pressure storage tanks are used for the storage of the more volatile fluids having a true vapor pressure exceeding the pressure limits of API 650, but not more than 15 lbf/in^2 (103 kPa) gauge. Light crude oil, gasoline blending stock, light naphtha, pentane, volatile chemicals, liquefied petroleum gas (LPG), liquefied natural gas (LNG), liquid oxygen, and liquid nitrogen are examples of liquids that may be stored in low-pressure storage tanks.

API 620, Appendixes R and Q, and ACI 376 provide single-wall and double-wall construction details.

4.3.3 Types of Low-pressure Storage Tanks

Tanks that have cylindrical shells and cone or dome roofs are typically used for pressures less than about 5 lbf/in.^{2} (34.5 kPa) gauge. Tank bottoms may be flat or have a shape similar to the roof. Hold-down anchorage of the shell is

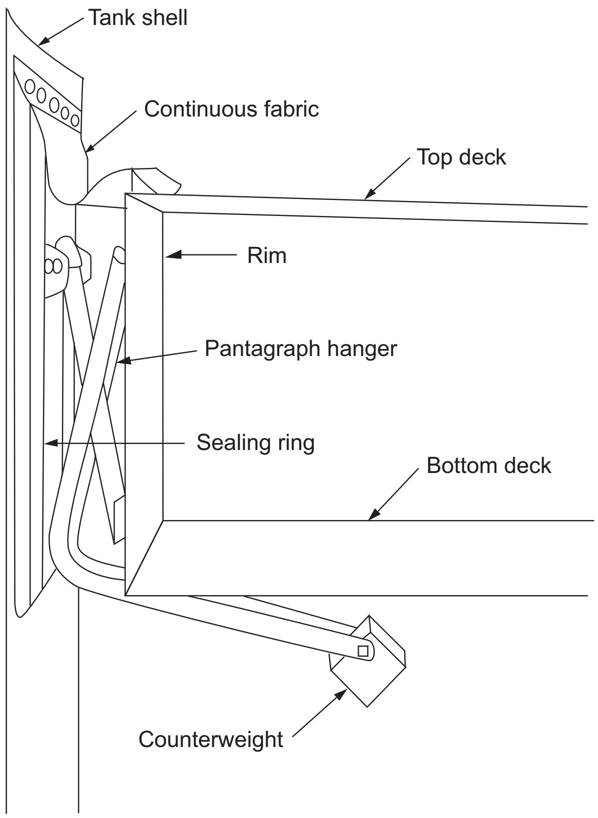


Figure 11—Floating Roof Using Counterweights to Maintain Seal

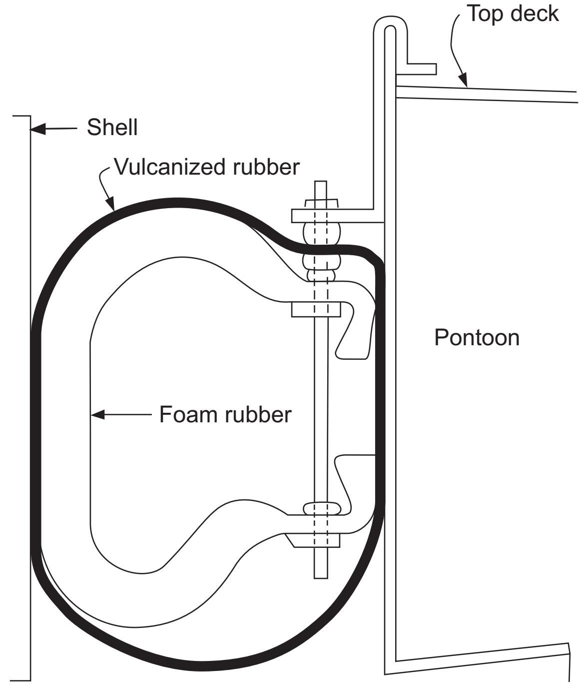


Figure 12—Floating Roof Using Resilient Tube-type Seal

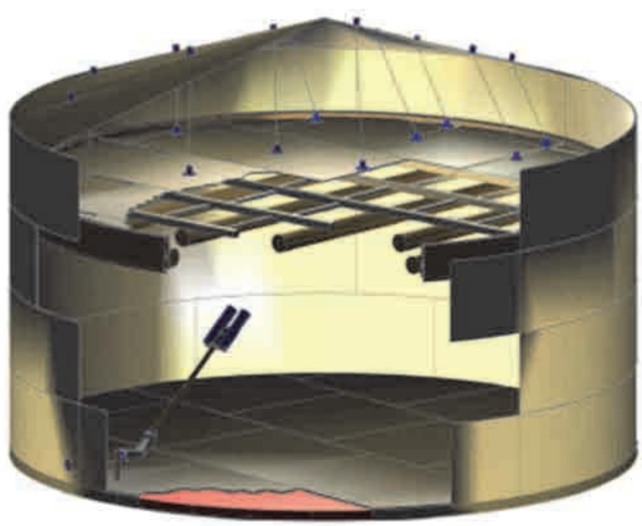
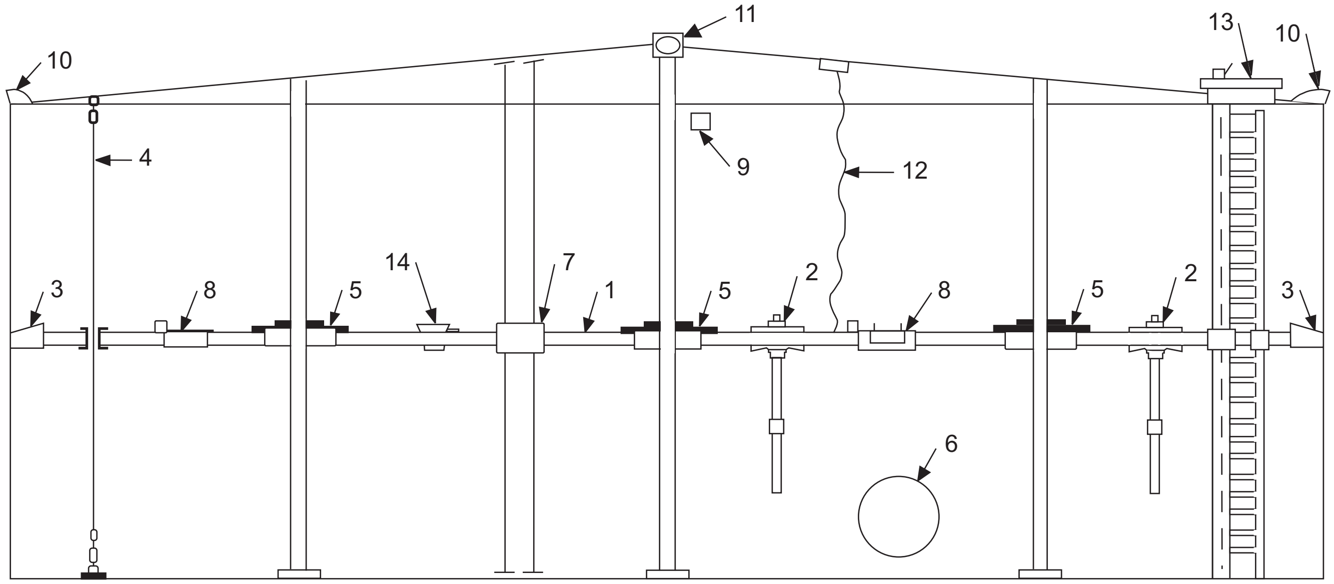


Figure 13—Cable-supported Internal Floating Roof Tank



Notes:

1. roof cover
2. support legs
3. seal
4. anti-rotation device
5. column negotiating device
6. manway
7. gauge floatwell
8. vacuum relief device
9. overflow vent
10. peripheral roof vent
11. center roof vent
12. anti-static grounding
13. roof hatch
14. gauge funnel

Figure 14—Typical Internal Floating-roof Components

generally required. For pressures above about 5 lbf/in.^{2} gauge (34.5 kPa) gauge, hemispheroid, spheroid, and noded spheroid tank types are commonly used. Tanks for this application are now typically constructed as spheres. Such tanks are designed to withstand the vapor pressure that may be developed within a tank having no devices or means to change or relieve the internal volume. As with atmospheric storage tanks, these tanks are provided with relief valves to prevent pressures from rising above design values.

Tanks with a plain spherical roof and tanks with a noded spherical roof are shown in Figure 21 and Figure 22, respectively; and cross-sectional view is shown in Figure 23. Figure 25 shows a spherical roof with a knuckle radius or smooth transition at the intersection of the shell and top head.

The spheroid uses elements of different radii, resulting in a somewhat flattened shape as shown in Figure 21. The noded spheroid, shown in Figure 26, is used for larger volumes, and internal ties and supports help to distribute the shell stresses. Figure 27 shows a cross-section of a noded spheroid. Noded spheroids are no longer constructed; they have been replaced either by spheres or by vertical cylindrical storage tanks as referenced in API 620.

4.3.4 Tank Systems for Refrigerated, Liquefied Gas Storage

API 625, Section 5, defines and describes various storage concepts for refrigerated liquefied gas tank systems. These include single, double, and full containment concepts. Some of these concepts are briefly described as follows.

a) **Single Containment**—this system incorporates a liquid-tight container and a vapor-tight container. There are several variants to the single containment concept such as the following.

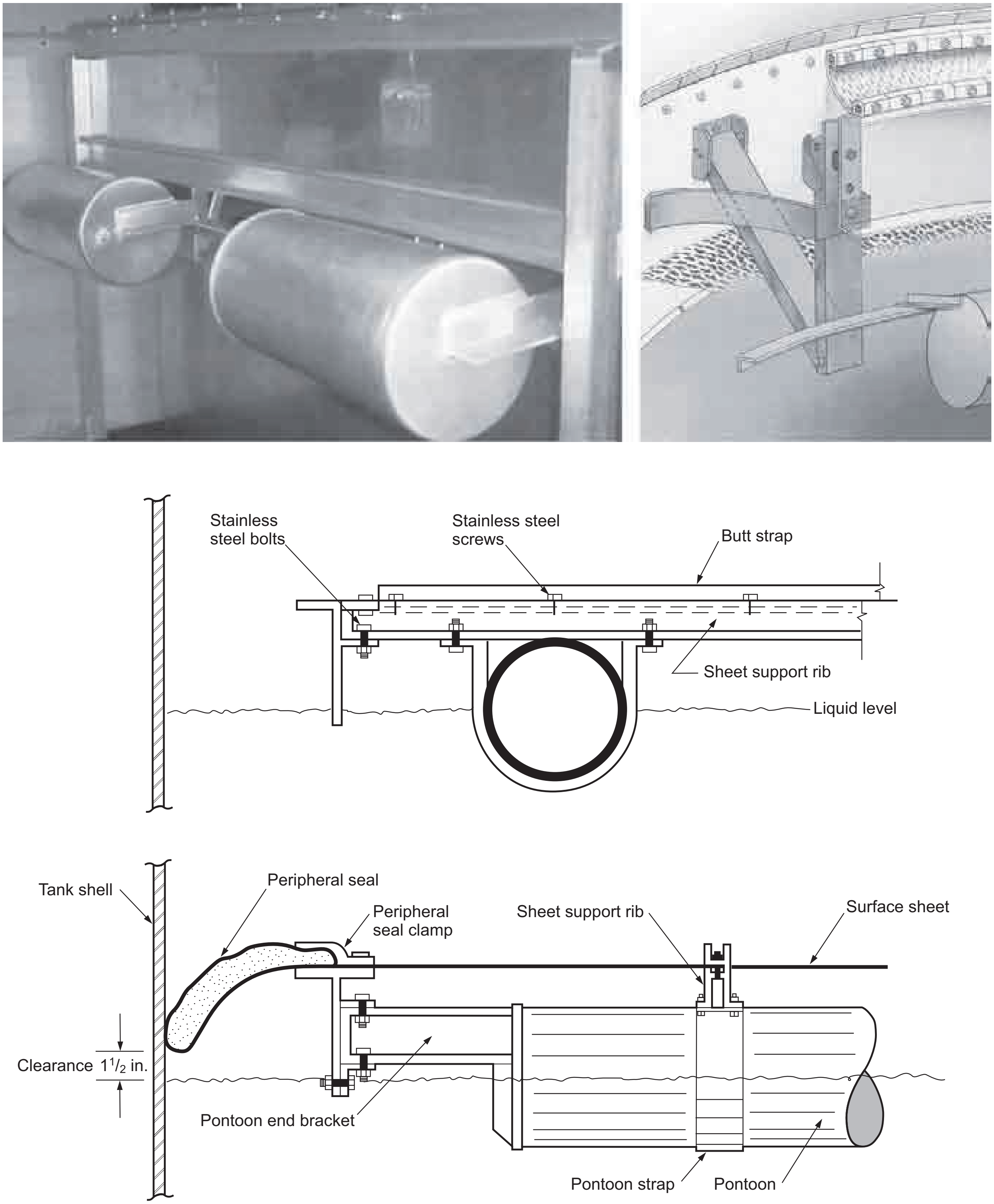


Figure 15—Typical Arrangement for Metallic Float Internal Floating-roof Seals

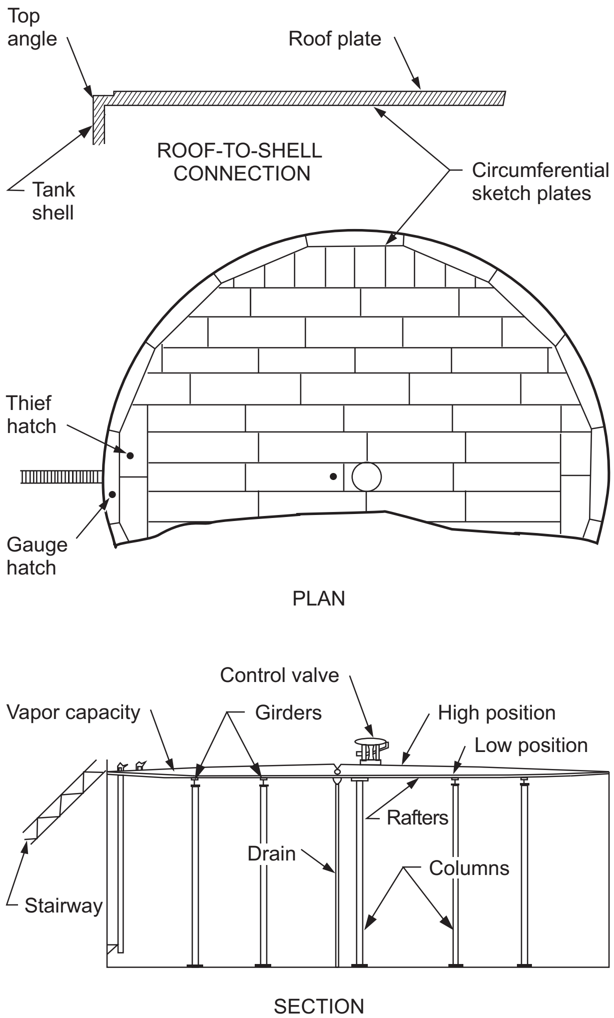


Figure 16—Plain Breather Roof Tanks

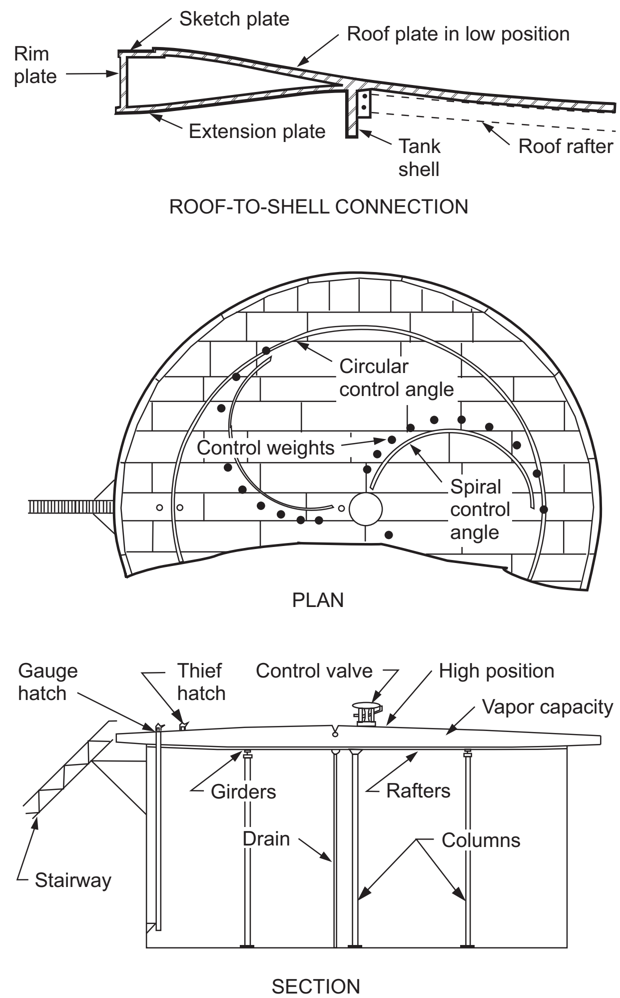


Figure 18—Balloon Roof Tank

Figure 17—Tank with Vapor Dome Roof

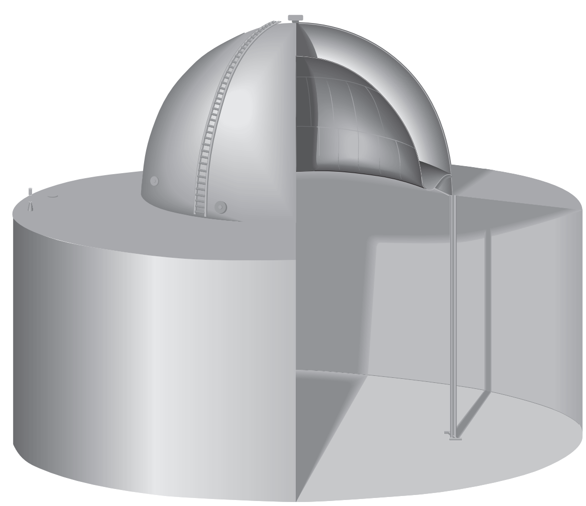


Figure 19—Cutaway View of Vapor Dome Roof

Figure 20—Welded Horizontal Tank Supported on Saddles

1) Single wall—Single low temperature steel or concrete tank containing the cold liquid with warm vapor containing roof, suspended deck with insulation and external wall insulation. (See API 625, Figure 5.1.)

2) Single wall—Single low temperature steel or concrete tank containing the cold liquid with low temperature vapor containing roof, external roof insulation and external wall insulation. (See API 625, Figure 5.2.)

3) Double wall—Single low temperature steel or concrete tank containing the cold liquid with a warm vapor containing roof, suspended deck with insulation, annular space insulation, and warm vapor containing outer tank (concrete or steel). (See API 625 Figure 5.3.)

4) Double wall—Single low temperature steel or concrete tank containing the cold liquid with low temperature vapor containing roof, external roof insulation, annular space insulation, and warm vapor containing outer tank (concrete or steel). (See API 625, Figure 5.4.)

b) **Double Containment**—an inner tank (low temperature steel or concrete) containing the cold liquid surrounded by a secondary containment tank of steel or concrete, that holds any leaked liquid, but not any leaked vapor. There are several variants to the double containment concept such as the following.

Figure 21—Plain Hemispheroids

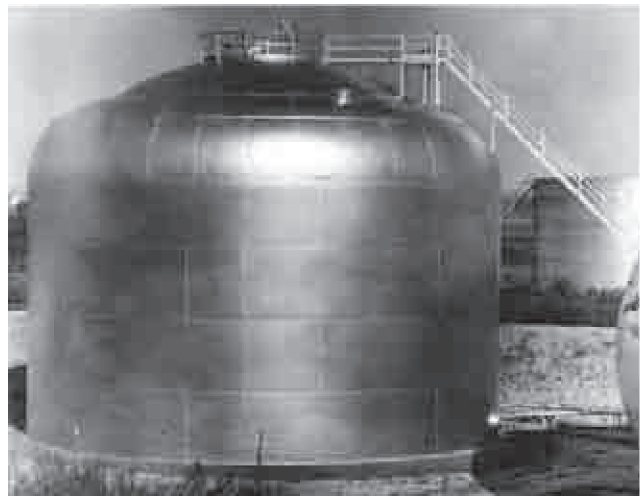


Figure 22—Noded Hemispheroid

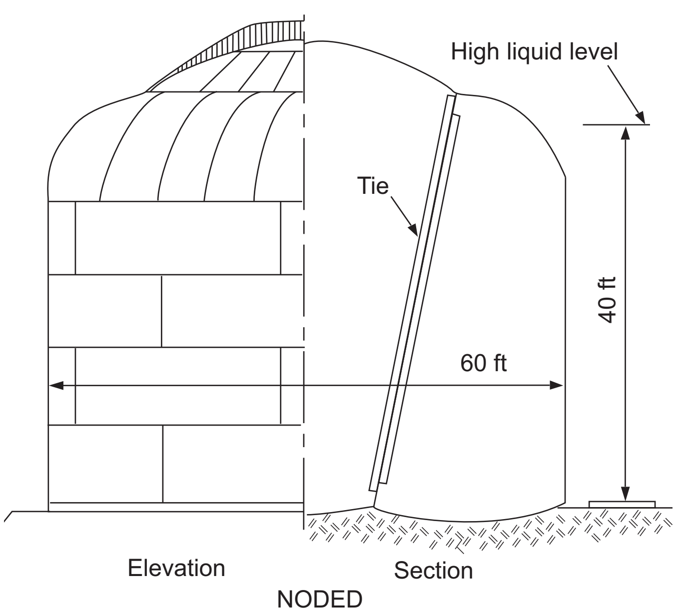


Figure 23—Drawing of Hemispheroid

Figure 24—Plain Spheroid

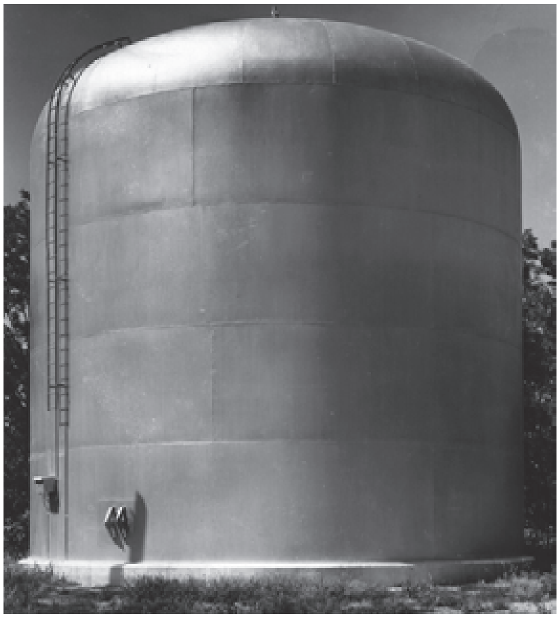


Figure 25—Plain Hemispheroid with Knuckle Radius

Figure 26—Noded Spheroid

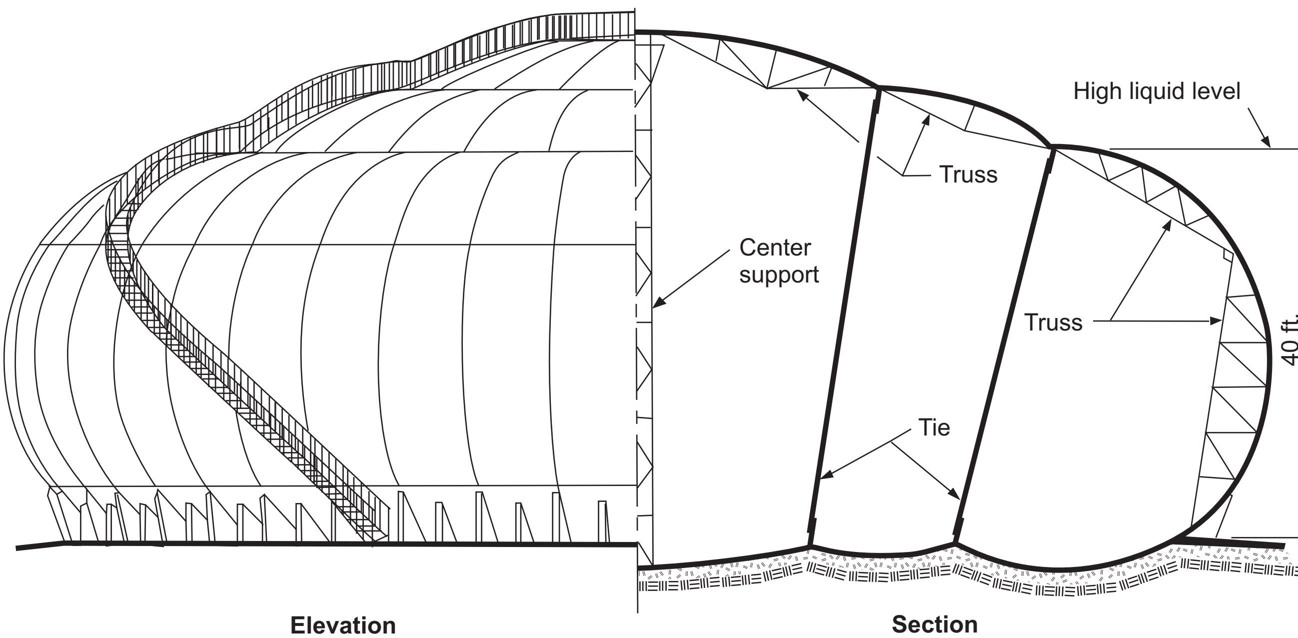


Figure 27—Drawing of Noded Spheroid

1) Low temperature steel or concrete primary liquid container, secondary low temperature steel or concrete secondary liquid container, suspended deck with insulation, warm vapor containing roof, and insulation on primary liquid container shell. (See API 625, Figure 5.5.)

c) **Full Containment**—an inner (low temperature steel or concrete) containing the cold liquid surrounded by a secondary containment tank of steel or concrete that holds any leaked liquid and provides for a controlled release of vapor. There are several variants to the full containment concept as follows.

1) Low temperature steel or concrete primary liquid container, secondary low temperature steel or concrete secondary liquid container, suspended deck with insulation, warm vapor containing roof, and annular space insulation between the liquid containers. (See API 625, Figure 5.7.)

2) Concrete primary liquid container, concrete secondary containment, and concrete roof. (See API 625, Figure 5.10.)

5 Reasons for Inspection and Causes of Deterioration

5.1 Reasons for Inspection

5.1.1 General

The basic reasons for inspection are to determine the physical condition of the tank and to determine the type, rate, and causes of damage mechanisms and associated deterioration. This information should be carefully documented after each inspection (see Section 10 for a list of example documentation). The information and data gained from an inspection contributes to the planning of future inspections, repairs, replacement, and yields a history that may form the basis of a risk based inspection (RBI) assessment.

The petroleum industry is committed to protecting the environment as well as the health and safety of its employees and the public at large. Therefore, minimizing the incidence of leaking petroleum storage tanks is a high priority for the industry.

5.1.2 Safety

One of the primary reasons to conduct periodic scheduled inspections is to identify deficiencies that could result in a process safety incident, such as loss of containment, which could lead to fire, toxic exposure, or other environmental hazard. These deficiencies should be addressed immediately through evaluation, further inspection, or repair when identified.

5.1.3 Reliability and Efficient Operation

External inspections performed while the equipment is in operation using non-destructive techniques may reveal important information without requiring entry into the tank. With such data, mechanical integrity can be maintained and fitness for service or risk based inspection (RBI) evaluations can be performed, which can aid in maximizing the period of operation without a shutdown. In addition, repair and replacement requirements can be planned and estimated in advance of a shutdown to more effectively utilize downtime. These efforts can therefore contribute to overall plant reliability by minimizing required downtime.

5.1.4 Regulatory Requirements

Regulatory requirements typically cover only those conditions that affect safety and environmental concerns. In general, regulatory bodies require the compliance with an industry standard or code, or adherence to Recognized and Generally Accepted Good Engineering Practice (RAGAGEP) when performing any inspection and repair activities.

API 653 was developed to provide an industry standard for the inspection of above ground storage tanks. It has been adopted by a number of regulatory and jurisdictional authorities.

Many regulatory groups (including OSHA in the United States) require that operating companies follow internal procedures in addition to applicable codes and standards. Internal procedures regarding inspection of tanks should encompass the requirements outlined in API 653 to help ensure compliance with many of the regulatory and jurisdictional authorities.

In the United States, the Environment Protection Authority (EPA) has issued a revised Spill Prevention, Control, and Countermeasures (SPCC) rule that covers most petroleum storage facilities. These regulations allow tank owners and operators to use industry standards and practices to implement and ensure an effective storage tank integrity program. Currently the most widely recognized tank inspection standards are API 653, API 12R1, STI SP001, and EEMUA 159.

Regulatory requirements for emission sources (such as floating-roof seals and tank vents) should be considered when establishing the inspection plans for tanks, as some environmental regulations may require intervals shorted than those stipulated by API 653. In some cases, more frequent inspections or additional inspections of some emission sources may be prudent.

Inspections are an important part of avoiding failures, maintaining safety, and optimizing availability. Therefore it is prudent to take a proactive approach towards storage tank inspection and maintenance to ensure continued integrity of the assets.

5.2 Deterioration of Tanks

Corrosion is the prime cause for the deterioration of steel storage tanks and accessories. Locating and measuring the extent of corrosion is a major reason for storage tank inspection. If left unchecked, tank deterioration can progressively lead to failure which may have adverse effects such as endangering personnel, environmental and property damage, and business interruptions.

5.2.1 External Corrosion

Atmospheric corrosion can occur on all external parts of a tank. The type of tank, construction details, and environmental conditions can all affect the location, extent, and severity of external corrosion. For example, a sulfurous, acidic or marine atmosphere can damage protective coatings and increase the rate of corrosion. External surfaces of the tank and auxiliary equipment will corrode more rapidly if they are not protected with paint or other coatings where surfaces are in contact with moisture or the ground. Extended contact with water is likely to cause localized corrosion. Such susceptible areas should be protected with coatings designed to withstand long-term immersion. Inspections should target areas where tank construction details cause water or sediment to accumulate.

External corrosion of tank bottoms can be significant. The foundation material used for forming a pad that is directly in contact with the steel bottom plates may contain materials that promote corrosion. For example, cinder may contain sulfur compounds that become very corrosive in the presence of moisture. The presence of clay, wood, gravel, or crushed stone as contaminants in a sand pad may cause pitting corrosion at each point of contact. Faulty pad preparation or poor drainage may allow water to remain in contact with the tank bottom. If a tank previously leaked corrosive fluid through its bottom, accumulation of the fluid underneath the tank can cause external corrosion of the bottom plates. For tanks that are supported above grade, an improperly sealed ringwall, as shown in Figure 28, may allow moisture to accumulate between the tank and the support, thereby accelerating corrosion. Asphalt-impregnated fiberboard is not a recommended sealant for tanks sitting on concrete ringwall foundations. The lower tank shell can become severely externally corroded near the grade line where soil movement has raised the grade level to cover the lower portion of the shell. External corrosion also occurs when insulation absorbs ground or surface water by wicking action, or when damaged or improperly sealed openings around nozzles and attachments allow water behind insulation. Containment areas should be drained as soon as possible after water accumulates to minimize the possibility of bottom or lower shell corrosion.

Figure 28—Foundation Seal

Riveted tanks are becoming increasingly rare in refinery and petrochemical plant operations, as they are difficult to design, construct and maintain. However, some riveted tanks are still in service, and are included in inspection plans. API 650 does not provide guidance for the construction of riveted tanks. Therefore, other design and construction standards should be referenced. Riveted tanks have many niches where concentration cell corrosion can occur (see 8.2.9). Leaks at the seams of riveted tanks may cause failure of external coatings, allowing external corrosion to develop.

5.2.2 Internal Corrosion / Deterioration

The occurrence of internal corrosion in a storage tank depends on the contents of the tank and its materials of construction. API 571 is a primary resource document for damage mechanisms in the refining industry and provides guidance as to the susceptibility, detection, and mitigation of most active mechanisms experienced in storage tanks. Inspectors can consult this document when developing the inspection plan for a tank to ensure that proper inspection and NDE is applied.

Crude oil and petroleum product tanks are usually constructed of carbon steel. Internal corrosion of these tanks in the vapor space (i.e. above the liquid level) can be caused by hydrogen sulfide vapor, water vapor, oxygen, or any combination of these. In the areas in contact with the stored liquid, corrosion is commonly caused by acid salts, hydrogen sulfide or other sulfur compounds, dew point corrosion, or contaminated water that settles out and mixes with solids on the bottom of the tank, typically referred to as bottom sediment and water (BS&W). Issues of stress corrosion cracking can be of particular concern when the product is known to be corrosive to welds and other heat-affected zones. Ethanol, DEA, and caustic products are just a few of the products that can contribute to this condition when in contact with bare metal.

In some cases, it is necessary to use linings (see API 652) that are more resistant to the stored fluid than are the materials of construction. In some particularly corrosive services, it may be necessary to construct the tanks of a more resistant material such as aluminum, stainless steels, or other alloys. These materials can experience deterioration from less common mechanisms such as caustic stress corrosion cracking, acid erosion, flow erosion, electrolytic reactions, and cyclic fatigue, among others.

5.3 Deterioration of Other than Flat Bottom and Non-steel Tanks

Tanks can be constructed of materials other than carbon steel. Aluminum, stainless steels and other alloys, wood, and concrete tanks can occasionally be found in refineries, chemical plants, and terminals.

Tanks constructed of wood can rot unless they are adequately protected. They also can deteriorate from infestation by insects such as termites. Unless kept continually moist, these tanks can shrink and may leak when refilled. If steel bands are present, the bands can be subject to atmospheric corrosion and may loosen under repeated cycling.

Concrete tanks can be attacked by the tank contents, crack because of ground settling or temperature changes, or spall due to atmospheric conditions, resulting in exposure of the steel reinforcement to further atmospheric corrosion.

Tanks constructed of materials such as aluminum, stainless steels, and other alloys are usually used for special purposes, such as food processing (for product purity), or because of product corrosion concerns. They are subject to some of the same mechanical damage mechanisms as carbon steel tanks. In addition, external stress corrosion cracking of stainless steel tanks may be a concern if chlorides that may be present in insulation get wet or enter the insulation. Aluminum can be affected by impurities such as acids or mercury compounds in process streams or wastewater.

Tanks can also be constructed of details that are not vertical, cylindrical, or flat bottomed. These tanks are usually classified as horizontal (axis of tank is in horizontal plane), skirt-supported, or column-supported with cone bottoms (with a vertical major axis). These latter tanks can be classified as bins or silos and very often hold granular or non-petroleum liquids or solids such as grain, cement, process liquids, carbon black, coker fines, and similar materials. Bins and silos, especially in granular product service, can suffer mechanical damage in operation including shell deformation and fatigue (from agitators or vibrators). Due to moisture entrapment, horizontal tanks on saddle supports can experience external corrosion at the saddle-to-tank interface. These areas are often inaccessible and difficult to inspect with normal inspection methods.

It is not possible to present all of the different or specific details that can be present in wooden tanks, concrete tanks, or steel bins and silos in this document. Careful examination and assessment should be planned based on prior inspection or similar service issues, type of construction details, and materials of construction. Structural integrity assessment may require use of a qualified engineer familiar with the type of tank design and operation in question.

5.4 Leaks, Cracks, and Mechanical Deterioration

Storage tanks should be inspected for leaks (current or imminent) or defects to minimize or prevent loss; hazard to personnel; pollution of air, ground water, and waterways; and damage to other equipment.

Brittle fracture and sudden loss of the contents of a tank can result in injuries to personnel and extensive damage to equipment in surrounding areas. Pollution of streams or waterways can result when such a tank failure occurs near a waterway or is connected to one by a sewer or other flow channel. Figure 30 illustrates the complete loss of a tank from brittle fracture. Proper design, fabrication, operation, inspection, and maintenance will minimize the probability of brittle fracture. A detailed discussion of brittle fracture can be found in API 571. API 653, Section 5.3 provides a procedure to assess the risk of tank failure due to brittle fracture and guidance for lowering the risk of brittle fracture.

Leaks are primarily the result of corrosion but can occur at improperly welded or riveted joints, at pipe thread or gasket connections or cover plates, or at crack-like flaws (including arc strikes on plates) in welds or in plate material. Three-plate laps in lap-welded tank bottoms are particularly prone to defects that can lead to leaks.

Crack-like flaws can result from a number of causes including deficiencies in design, fabrication, and maintenance. The most likely points for crack-like flaws to occur are at the bottom-to-shell details, around nozzle connections, at manholes, around rivet holes or around rivet heads, at welded brackets or supports, and at welded seams. The lower-shell-to-sketch-plate or shell-to-bottom weld is especially critical because in relatively large or relatively hot tanks there is a higher likelihood for this detail to develop a crack-like flaw due to high stresses. Potential for this occurrence can be minimized by the use of thicker, butt-welded annular bottom plates, which are required by API 650 for higher design stress tanks and for larger elevated temperature tanks (see API 650, Sections 5.5 and M.4.1, respectively). Photographs of typical crack-like flaws in tanks are shown in Figure 29, Figure 31, and Figure 32. Other cracking mechanisms are possible, including stress corrosion cracking (SCC).

Many other types of mechanical deterioration can develop over the service life of a storage tank. If such deterioration is discovered early through inspection, continued deterioration can be minimized and potential failures and leaks can be prevented. Early detection of deterioration and conditions that cause deterioration permits cost-effective maintenance and repair to be done on a scheduled basis, minimizing the risk of failure. Examples of such

Figure 29—Cracks in Tank Shell Plate

Figure 30—Extensive Destruction from Instantaneous Failure

deterioration can include severe service conditions like frequent fill/withdrawal cycling or elevated temperature (see API 650, Appendix M) affecting the integrity of the shell-to-bottom weld.

Settlement of a tank due to soil movement under the tank or tank foundation can also cause mechanical deterioration. Uniform settlement of the entire tank would not necessarily cause structural damage or be considered a serious issue. Large or uneven amounts of settlement can cause nozzles with attached piping to become over-stressed and possibly deformed or cracked, or may affect the normal operation of a floating roof. Significant amounts of uneven settlement should be cause for concern and for further investigation. Edge settlement in tanks with cone-down bottoms can trap BS&W, resulting in bottom and lower shell corrosion in this area. Soil and water can also be retained against the external shell when such settlement is present.

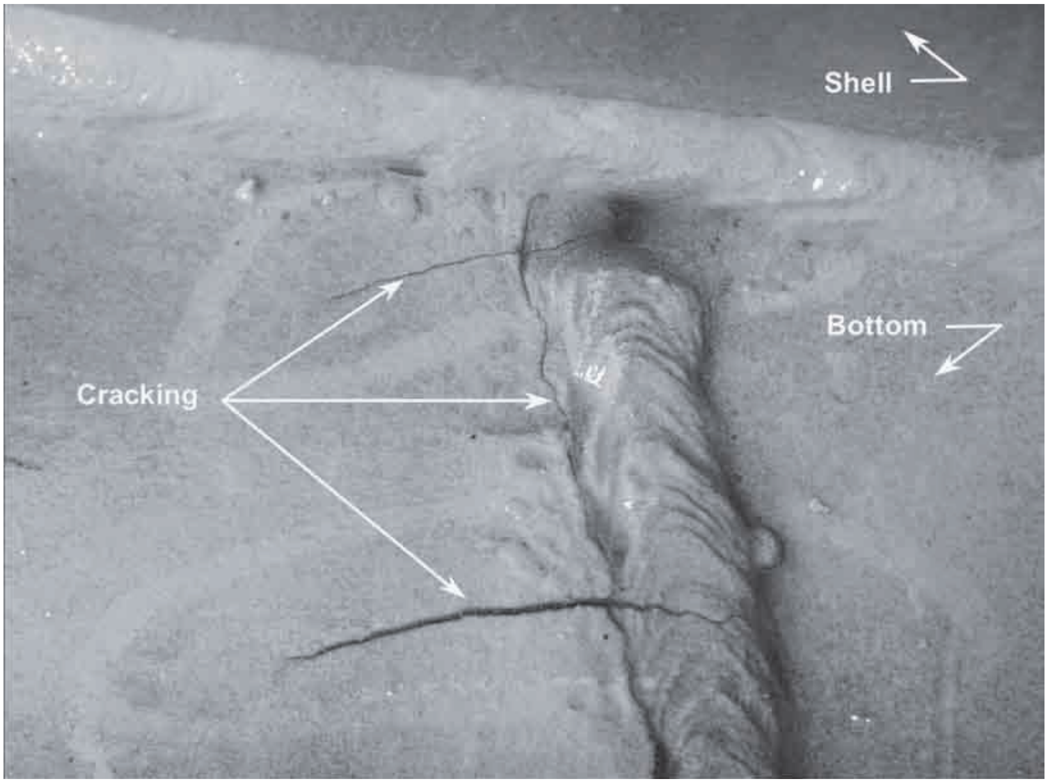


Figure 31—Cracks in Bottom Plate Welds Near the Shell-to-bottom Joint

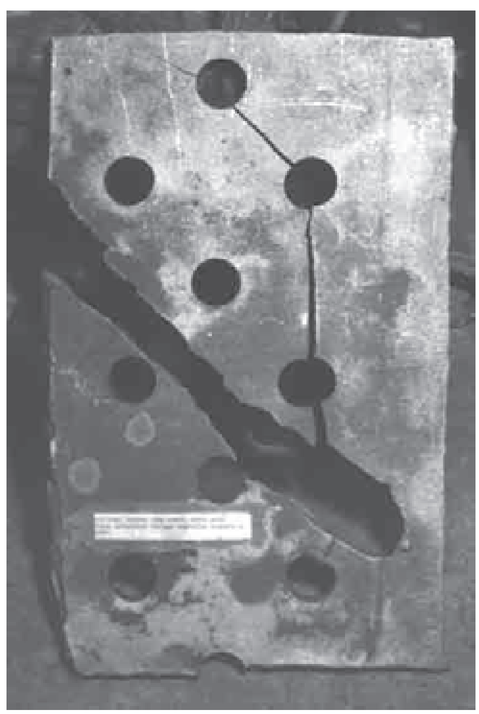
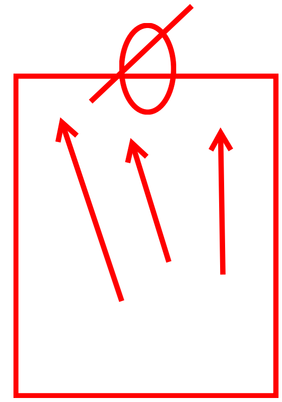


Figure 32—Cracks in Tank at Riveted Lap Joint to Tank Shell

5.5 Deterioration and Failure of Auxiliary Equipment



Pressure-vacuum vents and flame arrestors can fail to operate for the following reasons:

a) the presence of fouling material or debris;

b) corrosion between moving parts and guides or seats;

c) deposit of foreign substances by birds or insects;

d) formation of ice;

e) accumulation of grit-blasting material;

f) the covering of the vent opening with plastic or the plugging of vent openings with paint during painting operations that is not subsequently removed;

g) tampering by unauthorized personnel.

Examination of tank venting devices should be included in a periodic inspection to ensure that their proper operation and protection are maintained. API 576 provides information regarding inspection of pressure-relieving devices.

Gauge float leakage can be caused by corrosion or cracking. Inoperative pulleys, bent or broken float tapes, or plugged guides can cause float-type gauging devices to become inoperative.

Equipment for draining water from floating roofs can be rendered inoperable by plugging or by mechanical damage caused by debris, ice, or rotation of the floating roof. Drain piping, mechanical joints, and hoses can develop leaks that will allow the tank contents either to leak from the roof drain system or allow water to flow into the tank. For single deck floating roofs, leakage of the tank contents onto the floating roof may be sufficient to submerge or sink the roof. Inoperative drains with installed plugs (or with closed valves) can cause enough rain water to accumulate on the roof to sink a pontoon-type floating roof.

Deterioration of auxiliary equipment—such as ladders, stairways, platforms, wind girders, and shell stiffeners—can occur from corrosion, wind, and other external forces. Mechanical equipment such as mixers, swing line pontoons, piping and swing joints, diffusers, jet nozzles and other flow direction details, baffles, rakes, and agitators can suffer from deterioration due to corrosion, wear from flow erosion, and mechanical defects.

API 653, Annex C includes inspection checklists for many types of deterioration of storage tank auxiliary equipment and other appurtenances. The tank inspector should be thoroughly familiar with these checklists.

6 Inspection Plans

6.1 General

An inspection plan is often developed and implemented for tanks within the scope API 653. An inspection plan should contain the inspection tasks, scope of inspection, and schedule required to monitor damage mechanisms and assure the mechanical integrity of the tank. The plan will typically:

a) define the type(s) of inspection needed, e.g. external;

b) identify the next inspection interval and date for each inspection type;

c) describe the inspection and NDE techniques;

d) describe the extent and locations of inspection and NDE;

e) describe any surface cleaning requirements needed for inspection and examinations;

f) describe the requirements of any needed pressure or tightness test, e.g. type of test, test pressure, and duration; and

g) describe any required repairs.

Other common details in an inspection plan include:

— describing the types of damage mechanisms anticipated or experienced in the tank;

— defining the location of the damage;

— defining any special access requirements.

Inspection plans for tanks can be maintained in spreadsheets, hard copy files and proprietary inspection software databases. Proprietary software, typically used by inspection groups, often assists in inspection data analysis and recordkeeping.

6.2 Developing an Inspection Plan

An inspection plan is often developed through the collaborative work of the inspector, engineer, corrosion specialist and operations personnel. They should consider several pieces of information such as operating temperature ranges, process fluid corrosive contaminant levels, material of construction, tank design and configuration, service changes since the last inspection, and inspection/maintenance history. In addition, other information sources can be consulted, including API and NACE publications, to obtain industry experience with similar services. All of this information provides a basis for defining the types of damage and locations for its occurrence. Knowledge of the capabilities and limitations of NDE techniques allows the proper choice of examination technique(s) to identify particular damage mechanism in specific locations. Ongoing communication with operating personnel when process changes and/or upsets occur that could affect damage mechanisms and rates are critical to keeping an inspection plan updated.

For tanks, inspection plans should address the following:

a) locations for inspection;

b) access requirements (scaffolding or other supports);

c) types of NDE to be used;

d) tank cleaning required;

e) specific surface preparation required (including paint or coating removal);

f) access requirements;

g) insulation removal;

h) considerations for roof inspection and access;

i) vents and vacuum breakers;

j) foundation issues;

k) seals and floating rook components;

l) cathodic protection;

m) liners and coatings.

Inspection plans may be based upon various criteria but should include a risk assessment or fixed intervals as defined in API 653.

6.2.1 Risk-Based Inspection (RBI) Plans

6.2.1.1 Inspection plans based upon an assessment of the risk associated with a tank failure (by determining the likelihood of failure and the consequence of failure) is referred to as RBI. RBI may be used to determine inspection intervals and the type and extent of future inspection/examinations. API 580 details the systematic evaluation of both the likelihood of failure and consequence of failure for establishing RBI plans. API 653 outlines the requirements and limitations for performing an RBI assessment for a storage tank. In addition, regulatory requirements in the applicable jurisdiction should be considered to determine acceptability of using RBI for inspection planning and scheduling.

6.2.1.2 Identifying and evaluating potential damage mechanisms, current tank condition and the effectiveness of the past inspections are important steps in assessing the likelihood of a tank failure. The likelihood assessment should consider all forms of degradation that could reasonably be expected to affect tanks in any particular service. Examples of those degradation mechanisms include: internal or external metal loss from an identified form of corrosion (localized or general), all forms of cracking, including stress corrosion cracking (SCC) (from the inside or outside surfaces of a tank), and any other forms of metallurgical, corrosion, or mechanical degradation, such as fatigue, embrittlement, creep, etc. See API 571 for details of common degradation mechanisms.

6.2.1.3 Identifying and evaluating the process fluid(s) in the tank and the potential for injuries, loss of containment, environmental impacts, and unit loss of production are important aspects in assessing the consequences associated with a failure of tanks.

6.2.1.4 Any RBI assessment should be thoroughly documented in accordance with API 580, defining all the factors contributing to both the probability and consequence of a failure.

6.2.1.5 After an RBI assessment is conducted, the results may be used to establish the inspection plan and better define the following:

a) the most appropriate inspection and NDE methods, tools, and techniques;

b) the extent of NDE (e.g. percentage or location of tank surface to examine);

c) the interval for internal, external, and on-stream inspections;

d) the prevention and mitigation steps to reduce the probability and consequence of a failure (e.g. repairs, operational procedures, cathodic protection, coatings, etc.).

6.2.2 Interval-based Inspection Plans

Inspection plans which are based upon the specific inspection intervals defined in API 653 are referred to as interval-based. The interval for inspections is based upon a number of factors, including the corrosion rate and remaining life calculations, applicable jurisdictional requirements and the judgment of the inspector, the tank engineer, or a corrosion specialist. The governing factor in the inspection plan for many tanks is the maximum appropriate interval for inspection of the floor, as most other components can be inspected externally.

7 Frequency and Extent of Inspection

7.1 Frequency of Inspection

API 653 provides requirements for inspection frequency of tanks built to API 650 and its predecessor, API 12C. API 12R1 provides guidance for inspection frequency for tanks built to API 12B, API 12D, API 12F, and API 12P (oil and gas production, treating, and processing services).

API 653 provides criteria for condition based inspection and scheduling of tanks utilizing internal and external visual inspection results and data from various NDE techniques (also refer to 6.2). API 653 also recognizes the use of alternative inspection methodologies. For example, robotic inspection is one possible approach to perform an assessment of the tank bottom and other internal components without personnel entry. The application of risk-based inspection (RBI) procedures to determine inspection intervals may result in longer or shorter inspection intervals (refer to 6.3, API 580, and API 581).

Although inspections are normally scheduled on intervals ranging from monthly to 20 years or more, some circumstances warrant immediate action to mitigate the potential for imminent hazards. For example, holes in the liquid or vapor space of the tank may pose immediate hazards. These holes can release flammable vapors, leading to serious incidents. Even without a substantial vapor release, the vapor space inside the tank may potentially be ignited by nearby hot work, lightning or other causes, leading to very serious incidents. Holes in tanks should either be immediately addressed or the tank should be taken out of service and the holes repaired.

In-service visual inspections are intended to be performed more frequently for early detection of changes or deficiencies, and should be performed on tanks covered by API 653. In-service inspections should include checking for corrosion, leaks, settlement, distortion, and determining the condition of the foundation, insulation systems, and paint systems. Observations, especially of a change in condition, should be documented and reported to qualified personnel, such as a tank specialist, for further assessment and evaluation. For example, indications of settlement may prompt a formal settlement analysis and/or a structured monitoring program. The interval of an in-service inspection should be based on experience and risk and should be determined by someone knowledgeable about the tank and its operation. In no case should the interval of in-service visual inspections be less than that prescribed by API 653.

After severe climatic events (e.g. high winds, high water, heavy rain or lightning strikes), it may be desirable to check potentially affected components. These components include, but are not limited to:

a) the external floating roofs for excessive water loads;

b) the foundation for deterioration;

c) the external floating-roof deck and seals to see if they have been damaged;

d) the shell for evidence of deformation due to excessive loading.

After significant seismic events the tank, floating roof, and associated tank piping should be carefully inspected.

If leakage is detected during an in-service inspection, a tank specialist should investigate to determine whether the leakage is caused by internal or external corrosion or some other condition that can be corrected while the tank remains in service. If the leak cannot be corrected with the tank in service, remedial steps should be taken as soon as possible.

Another aspect of inspection that is critical to safe operations is the inspection of floating roofs. In flammable liquid service, the floating roof is critical to reducing the potential for tank fires and/or explosions. Steel annular pontoon or double deck floating roofs are effective for this purpose. For internal floating roofs, the compartments should be checked, whenever there is an out-of-service inspection, for possible leaks in the pontoons. For external floating

roofs, the compartments should be inspected for leaks whenever there is an internal and an external inspection. The compartments should be liquid tight so that vapors cannot cascade from one compartment to the other. The inspector may want to note if the compartments are not vapor or liquid tight for owner/operator consideration.

API 650 encourages bottom leak protection for new tanks, including the use of release prevention barrier systems, cathodic protection, leak testing, etc. There are several different leak detection technologies or approaches, such as:

a) volumetric/mass leak detection methods;

b) acoustic emissions leak detection methods;

c) soil-vapor monitoring leak detection methods;

d) inventory control leak detection methods.

Many of the technologies used in leak detection are identified in API 334. These control measures should be inspected or tested periodically, as appropriate for the particular system and the risk involved. For example, external cathodic protection systems should be tested for performance as recommended by API 651.

API 2610 provides additional guidance regarding the inspection of tank appurtenances, accessories, and the surrounding area.

When applicable, inspectors should attempt to coordinate inspections while tanks are out of service for operational issues. This scheduling often requires knowledge of internal inspection intervals, operating schedules, and operating experience for the tank(s) involved. Internal inspection intervals may also be based on experience and risk as determined by someone knowledgeable with the tank(s) and its operation. In no case should the frequency of these inspections be less than that prescribed by API 653. This coordination requires knowledge of internal inspection intervals and operating experience for the tanks involved.

To minimize cost and reduce the generation of wastes, every effort should be made to consider completing all necessary maintenance when tanks are out of service for inspection.

7.2 Condition-based Inspection Scheduling and Minimum Acceptable Thickness

Inspections scheduled and performed based on the past, current, and expected future condition of a tank (and its components) is defined as condition-based inspection. To meaningfully evaluate the condition of a storage tank, one can evaluate the data from inspections and the limits of corrosion and other forms of deterioration that can safely be tolerated. For thinning, the remaining life of the tank component (e.g. bottom, shell or nozzle neck) can be established using the current thickness, the estimated measured corrosion rate, and the minimum acceptable thickness, The corrosion rate and the remaining life can be calculated from the following equations:

$$\text{remaining life (years)} = \frac{t_{actual} - t_{minimum}}{\text{corrosion rate}} = \text{the remaining life of a tank component in years,}$$

where

t_{actual} is the thickness measured at the time of inspection for a given location or component used to determine the minimum acceptable thickness, in inches (mm),

$t_{minimum}$ is the minimum acceptable thickness for a given location or component, in inches (mm),

$$\text{corrosion rate} = \frac{t_{previous} - t_{actual}}{\text{time (years) between } t_{previous} \text{ and } t_{actual}} = \text{in inches (mm) per year,}$$

where

$t_{previous}$ is the thickness at the same location as t_{actual} measured during a previous inspection, in inches (mm).

For uniform corrosion, a corrosion rate can be estimated by plotting the metal thickness two or more inspections against the inspection dates, as shown in Figure 33. An extension of the line drawn through the plotted points will provide an estimation of the time at which the metal will reach minimum acceptable limit. As small variation in operating conditions, temperatures, cathode protection, and other factors occur, corrosion rates can vary. This should be considered in estimating the time at which a minimum thickness will be reached. Most other forms of deterioration, such as corrosion pitting, mechanical damage from wind, cracking of the tank metal, and operating failure of accessories, do not take place at a steady rate; they are largely unpredictable. If the allowable limit of deterioration is calculated, knowing how long the tank will take to reach that limit establishes the service interval and next inspection. If the limit appears to be less than the desired service interval, repairs or replacements may be necessary prior to putting the tank back into service. If that limit exceeds the desired interval, repairs may be postponed until the next scheduled out-of-service inspection.

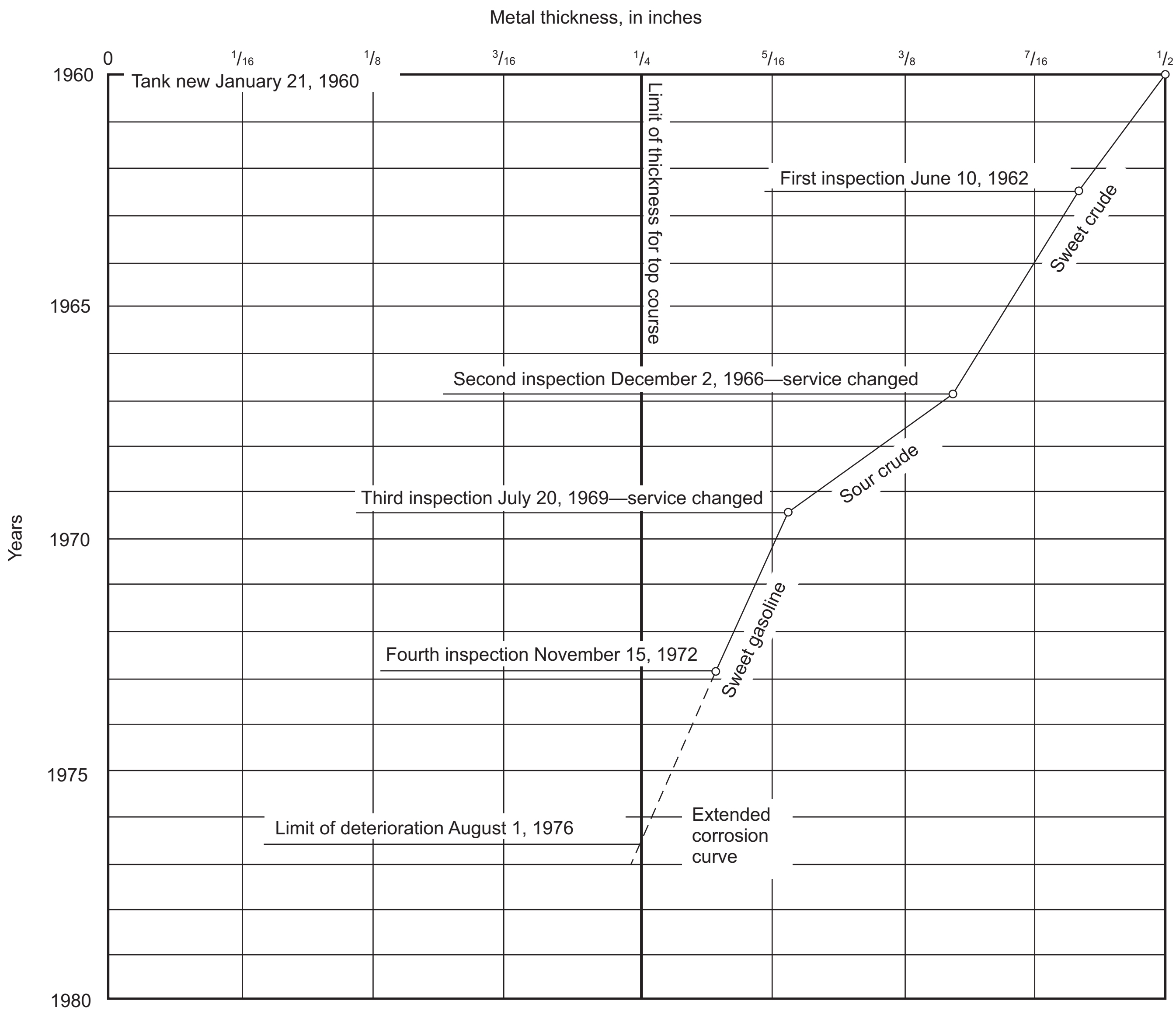


Figure 33—Hypothetical Corrosion Rate Curve for Top Course of Storage Tank

The above methodology presents an approach for estimating corrosion rate at a particular point. API 653 permits the application of empirical methods, statistical methods, or a combination of the two for estimating fitness-for-service and/or repair requirements. Statistical methods permit more flexibility regarding data collection and data analysis than empirical methods. With statistical methods, data from one or more inspections may be considered in a single analysis.

The minimum acceptable thickness should be determined based on the requirements identified in the applicable design standard (such as API 650, API 653, etc.). Additional factors that may need to be considered in order to determine an appropriate future corrosion allowance or to apply an additional safety factor include, but are not limited to, amount of information available on the tank; the type of service to the tank; the risk exposure given the contents and location of the tank; the stresses the tank is subject to; the reliability of current inspection data; the type of corrosion experienced; and the applicable regulatory requirements. For this reason, a storage tank engineer or tank specialist should determine what the minimum acceptable thickness is for a given tank component.

When the minimum acceptable thickness has been reached (further thinning may pose an integrity issue), action should be taken. The minimum acceptable metal thickness should be known for each tank and the methods of calculating the minimum thickness, under any given set of conditions, should be well established. The limits of other forms of deterioration usually will have to be determined based on good judgment, knowledge of all the conditions involved, and engineering analysis.

Because of the large number of variables affecting the minimum acceptable thickness and the great variety of sizes, shapes, and methods of tank construction, it is not possible to provide pre-calculated minimum or retirement thickness data in this document (see API 653 for further guidance). The preparation of retirement thickness tables is possible for all tanks in a given facility, and it may be desirable to include this information in the tank records.

Minimum acceptable thickness is calculated to withstand the product load, plus any internal (or external) pressure in the tank, plus a design allowance. Methods for determining the thickness of components in new storage tanks are given in the standards or codes to which the tank was constructed. Most of these standards are listed in Section 2. In most cases, the new thickness includes some excess thickness. This excess thickness may be the result of any one or all of the following factors:

a) additional thickness added to the minimum acceptable thickness as a corrosion allowance;

b) additional thickness resulting from using the closest, but larger, nominal plate thickness, rather than the exact value calculated;

c) additional thickness from deliberately setting the minimum acceptable thickness of plates for construction purposes;

d) additional thickness on the upper portions of shell courses not required for product loading at that level;

e) additional thickness, available due to a change in tank service or a reduced operating fill height.

The excess thickness described under item b above will normally be rather small; but with low corrosion rates, it can provide additional useful service life.

Newer tanks (tanks built to API 650, Seventh Edition or later) may have an original plate thickness based on the specific gravity of the product to be stored or based on hydrostatic test requirements, whichever results in a thicker plate. Tank bottoms resting on grade and the roofs of atmospheric storage tanks are subjected to practically no membrane stresses from product loads. Bottom areas, away from the shell or annular ring, need to be only thick enough to be leak tight and to meet the minimum acceptable thickness requirements specified in API 653. The roof must also be thick enough to support its own weight plus the design live load. Roofs and bottoms are often considerably thicker than necessary to withstand service stresses.

The pressure exerted on the sides of storage tanks by the weight of the liquid contained is greatest at the bottom and uniformly decreases up the shell. Because of this uniform pressure decrease, the shell plates above the bottom course may be thicker than needed for just product loading but this should be verified by calculation. For flat bottom cylindrical tanks, see API 650 for shell thickness calculations. For tanks subject to external pressure loadings, the required shell thickness should be calculated per Appendix V of API 650. The thickness required to withstand external pressure loadings does not decrease as you move up the tank shell wall.

If corrosion should occur in the shell, excess thickness may be available such that a safe fill height evaluation will result in the tank being able to remain in service longer.

Storage tank shell plate thickness is normally calculated to contain a fluid of a desired specific gravity (usually water in the case of atmospheric storage). If the actual service conditions are different from those contemplated in the design—for example, a stored fluid with a lesser specific gravity, a lower vapor pressure, or both—the existing shell courses may have excess thickness. Conversely, if the walls have corroded, it may be necessary to reduce the allowable safe fill height of the tank or change the product stored to one with a lower specific gravity. Certain stored products may have a specific gravity greater than 1.0 and the shell plate thickness would be designed accordingly (the hydrostatic test condition will not control).

API 653 provides methodology for determining minimum acceptable thickness (due to hydraulic loads only) for tank plate in existing tanks. This methodology can be used for estimating a point at which a tank may require repair or replacement or for scheduling the next inspection. The result will be a thickness that will be the minimum acceptable for a particular location in the given tank. When that thickness is reached, repairs or replacement will be required. It should be kept in mind that a pit, or a very small area corroded to the retirement thickness, does not weaken the plate appreciably from the standpoint of resisting product loading but may result in a leak. Evaluation methods for such localized areas are described in API 653. Pitting of bottoms may be the determining factor in establishing the next internal inspection interval.

For many parts of atmospheric storage tanks, neither the minimum acceptable thickness nor the methods for calculating the thickness are given in the tank standards. Such parts include pontoons, swing lines, floating-roof drain systems, nozzles, valves, and secondary structural members. Roof supports, wind girders, platforms, and stairways are covered by rules in API 650 for atmospheric storage tanks and API 620 for low-pressure tanks.

For structural members and parts, such as roof supports and platforms, normal accepted industry practice for structural design (such as methods provided in the *Steel Construction Manual*. issued by the American Institute of Steel Construction) can be used to calculate the allowable loads of members in the new condition.

For external piping, nozzles, and valves, the methods provided in API 570 and ASME standards can be used to determine minimum acceptable thickness, inspections, and potential repairs.

Good engineering practice and inspection judgment is of great importance in determining the limits of deterioration, regardless of whether it is from corrosion or from other reasons; standards and recommended practices provide guidance but cannot substitute for knowledge and experience.

In northern or periodically wet climates, it is necessary to consider the climate when scheduling inspections. It is best to assume the worst-case repair when estimating project time. Starting at the end of the weather window, work backwards, allowing time for coating, repairs, inspection, cleaning, tank preparation, etc., in order to select a start date. In the Arctic and sub-Arctic, cold weather coatings may be required.

Structural integrity and leak avoidance should be a high priority when evaluating tank condition. Minimizing environmental damage, along with the long-term savings from avoiding clean-up costs and negative public opinion due to a tank failure or leak, can far exceed the savings from making only minimal repairs. Proper life cycle cost analysis and/or risk-based inspection methodology (see 6.3) will help in making environmentally responsible and cost-effective repair decisions.

7.3 Similar Service Methodology for Establishing Tank Corrosion Rates

The internal inspection interval (i.e. operating interval) for atmospheric storage tanks, as defined in API 653, Section 4.4.5.1, is governed by the corrosion rate of the tank bottom. Similar service is an approach to estimating corrosion rates using data from other historical tank inspection data. As required by API 653, the purpose of estimating rates is to determine how long a storage tank can be operated without failure of the tank bottom due to corrosion.

Similar service is recognized within industry as a means of scheduling internal inspection intervals in API 510, API 570, and API 653, which uses corrosion rates as the basis for establishing inspection intervals. Similar service is a simplistic approach to qualitative risk assessment.

Although measurement of bottom wall thicknesses during an internal inspection to calculate a corrosion rate is an important means of establishing the next internal inspection interval, positively establishing the remaining bottom thickness is based upon many factors such as the amount, quality, and extent of inspections. Often, multiple inspection methods are utilized to establish the minimum floor thickness (i.e. magnetic flux leakage with follow-up ultrasonic inspection) to ensure that the worst area(s) of soil-side corrosion have been detected. When an owner/user chooses to apply similar service to estimate tank bottom product-side and soil-side corrosion rates, the owner/user should consider the factors listed in Appendix B, Table B-1.

Similar service is an acceptable method for independently estimating corrosion rates and may be used in lieu of, or in addition to, actual measurement of corrosion rates. Similar service has been found to be useful for prioritizing tank inspection when no tank bottom inspection data is available for a tank that is in operation. Rather than taking a tank out of service to establish corrosion rates, careful consideration of relevant similar service experience can be used to determine appropriate inspection priorities. Similar service is also used to supplement an internal inspection by using the data measurements of the internal inspection as an independent check on the anticipated corrosion rates. If there is a high level of confidence in the results of similar service from extensive data collection and available historical information, the extent of the internal inspection can often be limited by reducing the number of coupons required or the percentage of the bottom scanned. Since tank bottom condition typically dictates internal inspection intervals, only tank bottom corrosion is emphasized in this discussion.

To use similar service it is generally appropriate to discuss the two aspects of tank bottom corrosion—product-side and soil-side corrosion. The similar service should be examined independently for both the product-side and the soil-side corrosion since the mechanisms and corrosion rates for each are independent of one another. As with any risk assessment approach, the owner/user should assess the inspection effectiveness of tank bottom thickness data used in the similar service assessment.

Similar service evaluation of soil-side corrosion rates is typically only useful for tanks located on a given site. Any given site may exhibit unique soil-side corrosion characteristics and extrapolating soil-side corrosion from one site to another may not be appropriate. Soil-side corrosion data may vary from negligible to very aggressive pitting with rates approaching 20 mils per year. The best source of soil-side corrosion rates comes from the examination of previously inspected tank bottoms from the same site.

Product-side corrosion is caused by the stored liquid. While many petroleum liquids have little to no corrosion, the tanks often carry a “water bottom” (bottom sediment and water, or BS&W), a layer of water that separates from the petroleum liquid. If the water is allowed to stand at the tank bottom or cannot be drained it may be corrosive and cause product-side pitting and corrosion. For petroleum crude oil tanks, water bottoms are often very aggressive sources of corrosion since the water contains various salts that increase corrosivity and are often stored at temperatures above normal, which also increases corrosion rates. Again, previous tank inspections are a reliable source of information about the nature of corrosion that occurs on the product-side of the tank bottom for that particular service. Table B.2 in Appendix B is an example of applying similar service principles to the product-side of the tank bottom.

To summarize, the corrosion experience at a site or in areas of similar soil conditions can represent the soil-side corrosion rates and be applied to a whole class of tanks. On the other hand, product-side corrosion rates can be

estimated from similar service in stock or stored product conditions that does not necessarily have to come from the local site. It should be noted that when using product-side corrosion rates from other sites, the owner/user should review the operating practices at all sites to ensure that they are similar (e.g. water draw frequency, product corrosivity, product temperature, etc.). Together this data may be used to establish overall bottom corrosion rates and set internal inspection intervals.

7.4 Fitness-For-Service Evaluation

Among other types of refinery equipment, aboveground storage tanks can be evaluated to determine fitness for continued service. API 579 provides fitness-for-service (FFS) evaluation criteria for tanks based on what is known or can be determined about the tank from various inspections. Different levels of assessment are provided depending on the information available for evaluation and resources (experience and money) available. FFS deals primarily with the evaluation of defects and flaws such as corrosion, pitting, crack-like flaws, laminations, and distortions that can affect remaining service life. Specific criteria for evaluating defects or flaws in tanks are also provided in API 579, Annex A, Section A.6.

8 Methods of Inspection

8.1 Preparation for Inspections

Before entering or re-entering any tank, appropriate safety precautions are necessary. These precautions are discussed in detail in API 2015 and API 2016. Generally, such precautions include, but are not limited to, the following.

a) Removal of hazardous gases.

b) Removal of gas-generating, pyrophoric, or toxic residues.

c) Isolation from any source of toxic or gas-generating fluids by the use of blinds or by disconnection/isolation.

d) Assurance of an atmosphere that contains sufficient oxygen. Where applicable, OSHA rules for safe entry into confined spaces should be followed (29 *CFR* Part 1910.146).

e) Potential for collapse of either fixed or floating roofs.

A tank should be sufficiently clean to allow adequate inspection. Tank cleaning methods will be dependent on the amount of scale, sediment, solid product, or other foreign material that is present on the surfaces to be inspected. For relatively clean product services, water-washing the internal surfaces may result in adequate cleanliness for inspection but it may be necessary to grit-blast or high-pressure water-blast internal surfaces and weld seams to achieve sufficient cleanliness for inspection.

It is advisable to make a visual inspection of overhead structural members, plate surfaces and all supports to ensure that there are no loose rafters, large patches of loose scale, weakened support columns or brackets, or any other object that might fall and cause personal injury. This visual inspection is also important to ensure that there is not a significant amount of liquid being retained on the floating roof, which could cause an unexpected collapse and become a hazard to personnel. To the extent possible, this overhead inspection should be conducted from the entry point or other suitable observation points before working in the tank.

All tools and equipment needed for tank inspection and personnel safety should be checked prior to inspection to verify that they are in good working condition.

Table 1 lists some of the recommended tools for tank inspection. Those items listed in Table 2 should be available in case they are needed.

Table 1—Tools for Tank Inspection

Pit gauge
Magnifying glass
Inside calipers
Hammer
Knife or scraper
Notebook
Outside calipers
Paint or crayon (chloride-free item for use on stainless steel)
Permanent magnet
Plumb bob and line
Portable lights
Square
Steel rule
Straightedge
Crescent wrench
Ultrasonic-thickness measurement instruments

Table 2—Useful Supplemental Tools

Carpenter's or plumber's level
Magnetic-particle inspection equipment
"Megger" ground tester
Liquid-penetrant inspection equipment
Radiographic inspection equipment
Abrasive-blasting equipment
Surveyor's level / transit
Sample removal cutters
Mirror
Vacuum box tester with soap solution
Bottom thickness scanning equipment
Tools/methods for bottom leakage detection
Sectional pole or remote control for ultrasonic-thickness
measurement instruments
"Holiday" testing equipment for coatings

Other support equipment that may be required for inspection can include planking, cribbing timbers, scaffolding, special rigging, and ladders. Special tank scaffolding that is safely mounted on wheels may be useful for efficient inspection and repair purposes.

It also may be desirable to have the following equipment and services available:

a) steam, water, or compressed air for ventilation;

b) water for cleaning;

c) water and pressure gauge for testing;

d) compressed air for pneumatic tools;

e) electric power for tools and lights;

f) fresh air breathing equipment.

In isolated locations, some of these necessary services may not be readily or economically available, and substitute methods may have to be employed. Natural ventilation over an extended period may be acceptable for dilution of product vapor to an acceptable level for personnel entry (see API 2015 and API 2016 for more specific guidance on ventilation).

Prior to conducting internal or external inspection, the inspector should thoroughly review any available inspection records to become familiar with previous problems and recommendations noted.

In preparation for inspection, it is important that all personnel working in the area and any who may enter the area be informed that personnel will be working in the tank. Confined space entry procedures may need to be followed (project safety personnel or owner operations personnel should be consulted as necessary to establish specific tank entry procedures). Personnel working inside the tank should also be kept informed when any other work close to the tank or on the exterior of the tank, particularly on the roof, is to be performed during inspection.

8.2 External Inspection of an In-service Tank

Much of an external inspection can be conducted while a tank is in service to minimize the length of time the tank will need to be out of service. See API 653, Annex C for a detailed checklist of suggested items to be inspected while the tank is in service.

8.2.1 Ladder and Stairway Inspection

Ladders and stairways should be examined carefully for corroded or broken parts. The condition of the ladder (vertical or rolling), stairway parts, and handrails may be checked by visual inspection and by sounding to determine whether these parts are safe for continued use. Stairways and other access details (vertical ladders) should be evaluated per OSHA recommendations as detailed in 29 *CFR* Part 1910.

Large tanks may have intermediate support stairways. When concrete pedestals are used for such supports, they should be checked for cracks, spalling, and other problems. A scraper can aid in determining the extent of any concrete deterioration. Bolts set in the concrete should be examined carefully for corrosion at the point of contact, where a rapid form of crevice corrosion can take place.

Ladder rungs and stair treads should be checked for wear and corrosion. In addition to loss of strength caused by metal loss, the tread can become slippery when the surface is worn smooth. Bolts and rivets should be checked for looseness, breakage, and excessive corrosion. Welded joints should be checked for cracks, undercut, lack of fusion, erosion, and other defects. Handrails should be shaken to give an indication of their soundness. Particular attention should be given to tubular handrails, which may have corroded from the inside. Crevices where water can collect should be closely checked by picking at them with a scraper or knife and by tapping them with a hammer. Such crevices can exist at bracket connections, around bolts and nuts, and between stair treads and support angles. If the

surfaces are painted, corrosion may exist under the paint film. Rust stains visible through the paint and a general lifting of paint are evidence of such corrosion.

8.2.2 Platform and Walkway Inspection

Platforms, elevated walkways, and external floating roof wind girders set up to be used as walkways can be inspected in the same manner as ladders and stairways. These details should also be evaluated per OSHA recommendations as detailed in 29 *CFR* Part 1910. The thickness of walking surfaces used by personnel can be checked at the edges with calipers and in other areas by tapping with a hammer. Low spots where water can collect should be checked carefully because corrosion may be rapid in such areas. Drain holes can be drilled in the area to prevent future accumulation of water. Platform supports should also be measured to determine thickness and should be checked for buckling and other signs of failure.

Defects not requiring repair before inspection can be marked with paint or crayon and recorded in field notes or by some other appropriate means including electronic media (digital photography, video, etc.).

In areas with high seismic activity, the platforms and connections between tanks should be reviewed for sufficient flexibility to accommodate anticipated tank movement.

8.2.3 Foundation Inspection

The foundations of tanks may be made of sand or other fill pads; crushed stone pads or stone-filled grade bands; steel and concrete piers, ringwalls, or natural earth pads. Pads should be visually checked for erosion and uneven settlement. The condition of foundations and tank supports should be evaluated in accordance with requirements of API 653.

Tank level can be measured by using a surveyor’s level or other appropriate device to check the amount of settlement. Measured settlement should be evaluated in accordance with API 653, Annex B guidelines. For tanks that are actively settling, records of settlement should be maintained. Concrete pads, base rings, and piers/footings should be checked for spalling, cracks, and general deterioration as shown in Figure 34. Scraping of suspected areas can uncover such deterioration.

The opening or joint between a tank bottom and the concrete pad or base ring should be sealed to prevent water from flowing under the tank bottom. Visual inspection, combined with some picking and scraping, will disclose the condition of this moisture barrier.

Wooden supports for small tanks, stairways, or other accessories can be checked for rot by tapping with a hammer, picking with a scraper, or probing with a knife or ice pick.

Steel columns or piers can be hammered or measured with calipers to check for corrosion. Caliper readings can be checked against the original thickness or against the thickness of uncorroded sections to determine any metal loss. Piers or columns should be examined to see if they are plumb. This operation may be done visually or plumb lines and levels can be used if more accuracy is desired.

8.2.4 Anchor Bolt Inspection

The condition of anchor bolts can usually be determined by visual inspection. A tap with a hammer to the side of the nut may reveal complete corrosion of the anchor bolt below the base plate (Figure 35 and Figure 36). Severe damage may not be detected by such a test. Visual inspection can be aided by removing the nuts one at a time, or supplemented by ultrasonic thickness examination. Anchor bolt nuts should be checked for a snug fit to the anchor chair top plate (i.e. there should be no distance between the location of the nut on the bolt and the anchor chair top plate).

Figure 34—Failure of Concrete Ringwall

Figure 35—Anchor Bolt

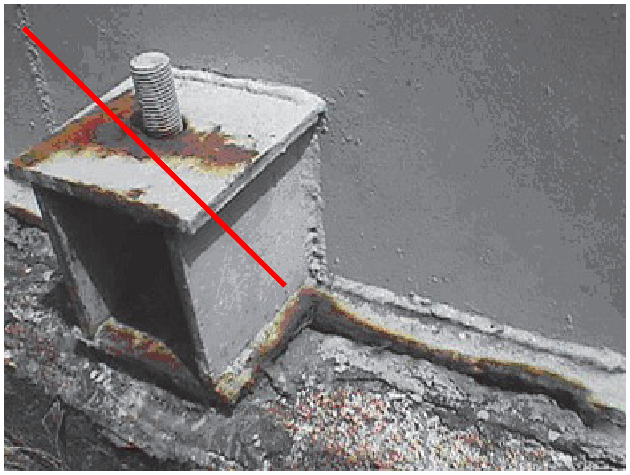


Figure 36—Corrosion of Anchor Bolts

8.2.5 Grounding Connection Inspection

Some tanks are provided with grounding connections. The grounding connections should be intact. They should be visually examined for corrosion at the point where they enter the earth or attach to a grounding rod and at the tank ground clip. If there is any doubt about the condition of the grounding connection, its resistance can be checked. The total resistance from tank to earth should not exceed approximately 25 ohms. API 545 provides information concerning the grounding of tanks to prevent ignition from static electricity, lightning strikes, or stray electrical currents.

8.2.6 Protective Coating Inspection

The condition of the protective coating on a tank should be adequately established during inspection. Rust spots, blisters, peeling, and cracking of the coating due to lack of adhesion are all types of common paint failure. Rust spots and blisters are easily found by visual inspection. Coating bond failure is not easily seen unless a blister has formed or has broken. ASTM D3359 provides a standardized test method for quantifying paint bond failure. Care should be taken not to significantly damage protective coatings during inspection. The coating inspection should identify areas of coating failure and the degree of active corrosion and existing corrosion damage.

Paint blisters most often occur on the roof and on the side of the tank receiving the most sunlight. Coating bond failure commonly occurs below seam leaks. Other points at which the paint may fail are in crevices or depressions and at tank seams that are welded, riveted, or bolted. The portion of the tank wall behind liquid level gauge boards is often overlooked as a location of deterioration. The paint on the tank roof is especially susceptible to accelerated failure. The paint on floating roofs should be inspected carefully, especially in areas where water or product is retained.

8.2.7 Insulation Inspection

If a tank is insulated, the condition of the insulation and weather jacket (if present) should be evaluated. Visual examination is normally performed. Detailed inspection should be conducted around nozzles, around the saddles of horizontal tanks, and at caulked joints. Areas of insulation may need to be removed prior to such inspection (usually removal is performed by personnel specializing in insulation application or removal), especially where the type of insulation is unknown. A few samples (cores) may also be removed—especially on the shaded side of the tank, on roofs, below protrusions, and at areas of obvious water intrusion—to better determine the condition of the insulation and the metal under the insulation. Insulation support clips, angles, bands, and wires should be spot-checked for tightness and signs of corrosion and breakage. If access is available internally, many of these areas (nozzle necks, external stiffeners, welded attachments) can be checked by UT from the inside. Significant corrosion can occur beneath insulation, at points near gaps in the weather protection, and in areas of the lower shell where the insulation may be in contact with surface water as shown in Figure 37 and Figure 38. Thermography and neutron back-scatter techniques to detect hot spots (or cold spots as the case may be) may also be useful in evaluating the condition of an insulation system in service. Corrosion under insulation (CUI) is most aggressive in temperature ranges between 120 °F (49 °C) and 200 °F (93 °C).

Inspectors should exercise great care when inspecting insulated tank roofs. Thin roof plates may not be strong enough to support the inspector, and insulation could be damaged, allowing water to enter. Means of properly distributing personnel loading should be used when accessing such roofs of unknown condition for inspection purposes.

8.2.8 Tank Shell Inspection

8.2.8.1 General

Inspection for paint failure to locate corrosion on the external surfaces of the tank (at the points of paint failure, under insulation, behind gauge boards, inside valve boxes, at points that have not been painted, and on unpainted tanks) can be of critical importance. Corrosion may occur on the shell near the bottom due to build-up of soil or other foreign matter and where product leakage occurs, especially if the tank contains corrosive materials.

Figure 37—Corrosion Under Insulation

Figure 38—Close-up of Corrosion Under Insulation

If any foreign material or soil has collected around the bottom of the shell or if the tank has settled below grade, a close inspection should be made at and below the grade line. The shell may need to be uncovered completely in these areas (removal is usually done by others) and inspected for corrosion. Accelerated corrosion often occurs at the grade line, as shown in Figure 39. Tanks with product at elevated temperatures in cold climates may have water present near the shell and under the bottom because of ice or snow build-up around the tank.

When evidence of extensive external corrosion or other types of deterioration justifies further inspection, it may be necessary to erect scaffolding for access to additional surfaces. Alternate rigging, portable ladders, cranes with man baskets, or man lifts can also be used.

Any evidence of corrosion should be investigated. Corrosion products or rust scale can be removed by picking, scraping, wire brushing, or blasting (with sand, grit, or water under high pressure) so that the depth and extent of the corrosion may be evaluated. Vigorous rapping with a hammer or with an air-driven chipping hammer with a blunt chisel can remove hard, thick rust scale. The potential hazards of using such methods should be evaluated beforehand. For example, hammer testing or removal of heavy scale should not be done with the tank under pressure or otherwise in service.

Figure 39—Corrosion (External) at Grade

8.2.8.2 Thickness Measurements

If corrosion is found, ultrasonic thickness (UT) measurements may be taken at the most corroded areas as one method of measurement. If much corrosion is evident, it is more effective to take several measurements on each ring or to scan the surface with a thickness-scanning device supplemented by ultrasonic prove-up. Numerous thickness measurements may be necessary for assessing thickness in accordance with API 653, Section 4 guidelines. It should be emphasized that when UT is used for establishing corrosion rates, other evaluation methods may also be appropriate. These include similar service or establishment of corrosion rates from past internal inspections or substitution of higher rates from the bottom when applied to the shell.

The depth of localized areas of corrosion can be measured by placing a straightedge long enough to span the corroded area on the longitudinal axis, then measuring from the straightedge to the lowest point of the corroded area. Isolated areas of corrosion can be measured by pit gauging.

Sun, shade, prevailing winds, and marine environments may affect the rate of external corrosion significantly. These factors need to be considered when determining the number and location of thickness measurements to be taken.

UT measurements may be taken on the upper shell courses from ground level by the use of a sectional pole or a remote-controlled scanning tool. UT measurements taken from the outside should be compared with thickness measurements that may subsequently be taken from the inside. In obtaining shell thickness, special attention should be given to the upper 24 in. (61 cm) of uncoated shells of floating-roof tanks. These portions of the shell plates can corrode at a higher rate than the lower shell plates because of constant exposure to the atmosphere on both sides.

UT measurements should be taken only by trained personnel using a properly calibrated thickness measurement instrument and an appropriate thickness measurement procedure. Coatings can affect UT thickness readings and the examiner may need to compensate for the coating when recording the metal thickness measured. Modern ultrasonic multi-echo thickness scopes, when properly calibrated, allow direct metal thickness readings to be taken through thin-film coatings.

8.2.8.3 Stiffeners and Wind Girders

The outside stiffeners and wind girders of a tank can be inspected visually and by hammer testing. Thickness measurements should be made at points where corrosion is evident. Outside calipers and a steel rule are usually adequate to take these measurements, although ultrasonic thickness measurements are more efficient and more accurate. Any pockets or crevices between the rings or girders and the shell should receive close attention. If the stiffening members are welded to the shell, the welds should be visually checked for cracks. If any evidence of cracking is found, the welds should be cleaned thoroughly by wire brushing or abrasive-blasting for closer inspection. For maximum sensitivity, the areas can be checked by the magnetic particle or liquid penetrant examination method. If the magnetic particle method is used for detecting cracks while the tank is in service, current flow (prod techniques) should not be used because of the danger of sparks. For this type of test, a permanent magnet or electromagnet (magnetic flow) technique should be used.

8.2.8.4 Caustic Cracking

If caustic or amine is stored in a tank, the tank should be checked for evidence of damage from caustic stress corrosion cracking, sometimes referred to as caustic embrittlement. The most probable place for this to occur is around connections for internal heating units or coils. This type of deterioration is manifested by cracks that start on the inside of the tank and progress through to the outside. If this condition exists, the caustic material seeping through the cracks will deposit readily visible salts (usually white). Figure 40 shows an example of caustic stress corrosion cracking. Thorough cleaning and checking with indicating solutions is necessary before welded repairs are conducted

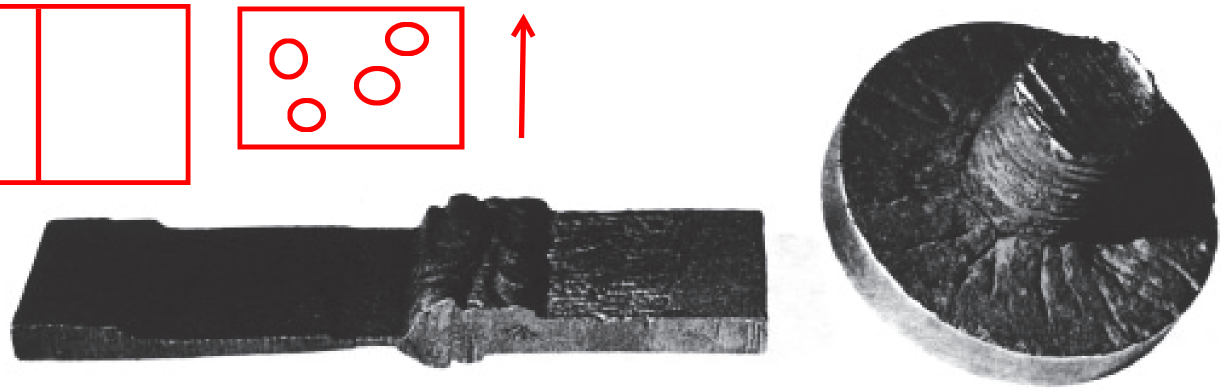


Figure 40—Caustic Stress Corrosion Cracks

on steel that has been affected by caustic stress corrosion cracking. Cracking may occur during welding repairs in such areas.

8.2.8.5 Hydrogen Blisters

The shell and the bottom of the tank should be checked for hydrogen blisters. This form of deterioration is discussed further in API 571. Figure 41 and Figure 42 show the types of blisters that can occur either on the inside or outside surfaces. They are found most easily by visual examination and by feel. Visual examination should be aided by use of hand-held lighting of sufficient candlepower (at least 100 lumens) under low ambient lighting conditions, holding the flashlight against the shell so the light beam shines parallel to the shell surface. Many small blisters can be found by running fingers over the metal surface. The location of large blisters should be recorded so that while the tank is out of service, further inspection of the area can be made.

8.2.8.6 Leaks, Crack-like Flaws, and Distortion

In addition to an examination for corrosion, the shell of the tank should be examined for leaks, crack-like flaws, buckles, bulges, and banding or peaking of weld seams.

Leaks are often marked by a discoloration or the absence of paint in the area below the leaks. Leaks are sometimes found by testing the tank as discussed in 8.5 or by other methods discussed in 8.4.6. The nature of any leaks found should be carefully determined. If there are any indications that a leak is believed to be due to a crack, the tank should be removed from service as soon as possible, and a complete inspection should be made to determine the repairs required.

Although cracks in tanks are not common, crack-like flaws can occur. These can be found at the connection of nozzles to the tank, in welded seams, and in the metal ligament between rivets or bolts, between a rivet or bolt and the edge of the plate, at the connection of brackets or other attachments to the tank, and at the connection of the shell to the bottom of a welded tank. When an angle detail (i.e. mechanical joint) is found at the bottom joint of a welded tank, crack-like flaws can occur in the shell plate. Usually, close visual inspection is sufficient when checking for crack-like flaws but for increased detection capability, liquid penetrant or magnetic particle examination should be used. If any signs of crack-like flaws do exist, the entire suspected area should be abrasive-blasted or otherwise adequately cleaned for magnetic particle (MT) or liquid penetrant (PT) examination.

Deformations will normally be readily apparent through visual inspection. Inspectors should consider that there could be slight deformations near a welded seam or elsewhere in the shell. Deformation can be measured by placing a straight edge lengthwise against the vertical shell or by placing a curved edge (cut to the radius of the shell) against the circumference. If deformation is present, it is important to determine the cause. Deformation can be caused by settlement of the tank, wind, earthquake, internal pressure in the tank due to defective vents or relief valves, an operating or induced vacuum in the tank, severe corrosion of the shell, movement of connected piping, improper welding repair methods, and other mechanical damage. Figure 43 shows an extreme case of tank deformation caused by inadequate vacuum venting. Settlement or frost heave of the soil beneath a tank bottom can cause deformation of the shell at the bottom edge. This can be checked with a straight-edge level placed vertically at locations around the bottom.

When a welded tank has significant deformations, weld seams may be highly stressed and can crack. The joints most susceptible to cracking are those at connections, at the bottom-to-shell joint, at floating-roof deck lap seams, the shell-to-roof joint, and at vertical shell seams. Failure of a shell-to-roof frangible joint detail is shown in Figure 44. When cracking is suspected, magnetic particle examination is the preferred method to use. In using this method, the seams to be inspected should be abrasive-blasted or wire-brushed clean. If the welded surface is rough or extends significantly above the surface of the joined plates, it may be necessary to grind the welds to obtain a reasonably smooth surface without sharp corners or discontinuities. Liquid penetrant and ultrasonic shear wave examination methods also can be used to find cracks. In addition, radiographic (RT) examination can be used, but it requires that the tank be emptied and prepared for personnel entry.

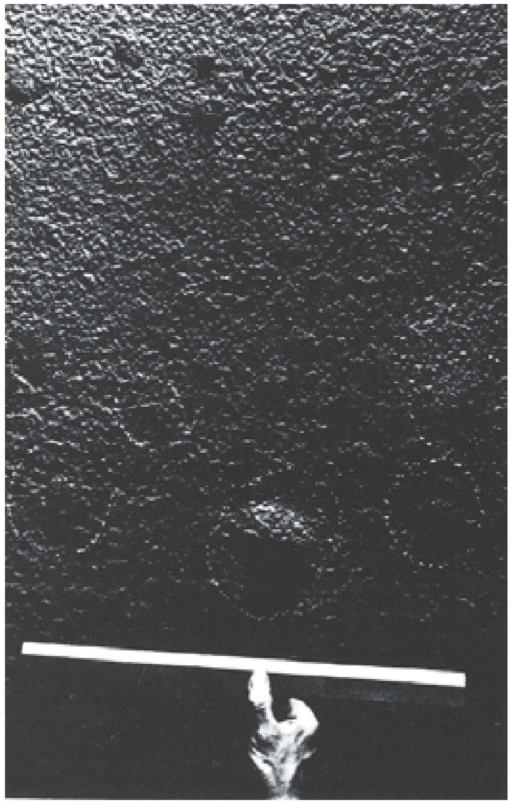


Figure 41—Small Hydrogen Blisters on Shell Interior

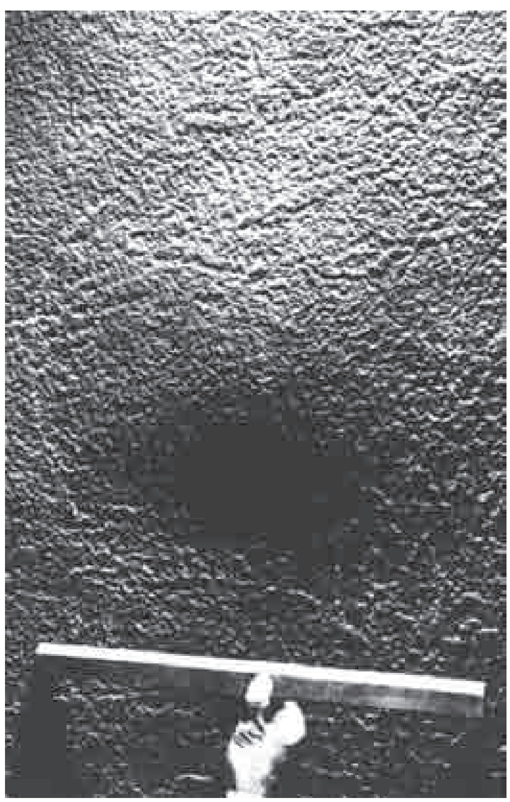


Figure 42—Large Hydrogen Blisters on Shell Interior

Figure 43—Tank Failure Caused by Inadequate Vacuum Venting

Figure 44—Roof Overpressure

8.2.8.7 Rivet Inspection

If the tank is of riveted or bolted construction, a number of randomly selected rivets or bolts should be checked for tightness. They may be checked by lightly tapping the rivet or bolt head laterally with a hammer while holding a finger against the opposite side in contact with the plate. Movement of the rivet or bolt should not be detectable. Bolts or rivets tested in this manner may need to have the paint touched up after tapping. It may be advisable to postpone this test until the tank is out of service and the rivets or bolts can be checked on the inside of the tank. Alternatively, broken rivet bodies or bolts can be detected by ultrasonic examination while a tank is in service.

8.2.9 Tank Roof Inspection

The roof or top head of a tank can be inspected for significant thinning by ultrasonic thickness examination or even by MFL scanning (if the roof condition is thought sound enough to withstand the weight of the equipment). Hammer testing may dislodge scale from the internal plate surfaces into stored product and is not a recommended method of establishing roof plate integrity for personnel loading. Suitable fall protection should be used when working on roofs. On a fixed roof, planks long enough to span at least two roof rafters should be laid and used as walkways, at least until the safety of the roof is determined. In general, the inspector should always walk on weld seams if they are present, because of the extra thickness available to support body weight. On a floating roof of unknown or questionable condition (e.g. insulated roof decks), the same precautions should be taken. In addition, because of the possible existence of harmful vapors, the floating roof should be as high as possible if volatile liquid is in the tank at the time of inspection.

If the tank is not full (i.e. floating roof at or near maximum fill height), appropriate atmospheric testing should be performed before personnel without respiratory equipment are allowed on the roof. It may be desirable to station a second employee with respiratory equipment on the platform to give assistance if necessary.

The runway, rollers, and treads of any rolling ladders on the roof of a floating-roof tank are subject to wear and distortion. The ladder can be checked in the same manner as outside ladders or stairs. If the ladder has come off the runway because of roof rotation (which could result from seismic loading, high winds or lack of suitable anti-rotation device), the roof—and especially the roof seals—should be examined visually for physical damage. The rollers on the ladder base should be freewheeling.

Grounding cables that connect the floating roof to the shell should be checked for breaks or damage. Broken grounding cables are common in freezing climates. Electrical shunts, if present, should be checked to ensure adequate contact between the floating roof and the shell.

Gaps between the shell and the seal(s) of a floating roof may be restricted by air quality regulations (local or federal). Minor emissions may be present at any time. Excessive emissions indicate improper seal installation, altered seal condition due to tank operations or long-term wear and tear or a malfunctioning seal(s) due to external influences (earthquake, high winds, snow and ice). Excessive emissions due to seal gaps can also result in rim space fires if a source of ignition (lightning strike) occurs. Visual inspection may be adequate to determine seal condition, and corrections may be possible while the tank is in service. If permanent repairs cannot be made, the defective areas and any temporary repairs should be noted in the records so that permanent repairs can be made when the tank is removed from service. Seal damage can occur if the maximum operating level is exceeded when portions of the seal are pushed up above the top angle or plate edge.

Drainage systems on floating roofs should be inspected frequently for leakage or blockage. If the drains are blocked, an accumulation of liquid can cause floating roofs to sink or to be severely damaged. This is especially true when the roof is sitting on its legs or has a poorly contoured deck that does not allow good drainage. Proper operation of check valves in drainage sumps should be verified on a regular schedule, especially for those in fouling or corrosive service.

In addition to the appropriate inspections performed on floating roofs and cone roofs, the vapor seals around columns and the ladder of covered floating roofs should be checked for leakage and condition. The ladder and columns should be checked for plumbness.

In areas where bottom settlement problems continue to occur in service, columns may subside due to uneven bottom settlement, causing cone roofs to deform and retain water. Depending upon severity, repairs may be necessary.

Platforms and guardrails on a roof should be checked carefully in the same manner as described earlier for stairways and ladders.

External corrosion on roof surfaces will usually be most severe at depressions where water can remain until it evaporates. When corrosive vapors in a tank leak through holes in the roof, pressure vents, floating-roof seals, or other locations, significant external corrosion may occur in these areas. Inspection for corrosion on the external surfaces of a roof may follow the same procedure as for the shell. UT measurements of badly corroded areas can be made if the thickness of the corroded roof plate is still within the range that the instrument can measure accurately. The inspector should be aware of the doubling effect of older types of ultrasonic instruments that are operated below their specified thickness range; for example, a 180 mil (4.6 mm) roof thickness may show up on a digital thickness meter as 360 mils (9.1 mm). Multi-echo ultrasonic measurement equipment, which can provide accurate thickness through thin-film coatings, should be used wherever possible.

8.2.10 Auxiliary Equipment Inspection

Tank pipe connections and bolting at each first outside flanged joint should be inspected for external corrosion. Visual inspection combined with scraping and picking can reveal the extent of this condition. See API 570 if piping beyond the first external tank flange is to be inspected. When external piping inspection is specified, the soil around the pipe should be dug away for 6 in. to 12 in. (150 mm to 300 mm) to allow for inspection, as soil corrosion may be especially severe at such points. After the pipe is exposed, it should be thoroughly scraped and cleaned to permit visual and ultrasonic thickness or other non-destructive examination.

Connected piping should be inspected for possible distortion if a tank has settled excessively, especially if the tank has been subjected to earthquake or high water levels. In the latter case, water draw-off and cleanout nozzles connected to the bottom may have been subjected to high shearing or bending stresses. Special attention should be given to such nozzles. In colder climates, frost heave can raise piping supports and place excessive bending moments on piping nozzles and shell connections. Internal explosions, high winds, and fires can also cause distortion. If there is any evidence of distortion or cracks around nozzle connections, all seams and the shell in this area should be examined for cracks. The area should be abrasive-blasted or wire-brush cleaned down to parent metal. Magnetic particle or liquid penetrant examination may be used for improved detection of crack-like flaws.

One of the most important aspects of piping integrity associated with the tank is sufficient flexibility to accommodate settlement or movement due to seismic activity.

Flame arrestors should be opened at appropriate intervals, and the screens or pallets should be visually inspected for cleanliness and corrosion. Bees and mud daubers occasionally plug arrestors. Solidification of vapors from the stored product may also restrict the flow area of the flame arrestor. If the venting capacity is seriously reduced under either pressure or vacuum conditions, the possibility of tank failure increases greatly. In the event of an explosion in a tank having a connected gas-collecting system, flame arrestors should be checked immediately for signs of damage.

Earthen and concrete dikes should be inspected to ensure that they are not eroded or damaged and are maintained at the required height and width. Masonry firewalls should be checked for cracks, erosion, or any other signs of deterioration. Stairways and walkways over dikes or firewalls should be inspected in the same manner as those on a storage tank. Drains for fire wall enclosures and dikes should be inspected to ensure that they are not plugged and that they are equipped with an operable drainage control valve.

Fire-fighting equipment attached to or installed on tanks—such as foam lines, chambers, connections, and any steam-smothering lines—should be visually inspected. These parts can be hammer-tested (as long as they are not under pressure), or ultrasonic thickness measurements can be obtained.

Pressure-vacuum vents and breather valves should be inspected to see that they are not plugged; that the seat and seal are tight; and that all moving parts are free and not significantly worn or corroded. Thickness measurements should be taken where deterioration is located. Plugging of the discharge side screen and build-up of solids on the pallets are common problems.

Cathodic protection systems should be maintained as indicated in API 651.

Other auxiliary equipment should be inspected to ensure that it is in an operable and safe condition. API 653, Annex C, contains detailed checklists for inspection of auxiliary equipment for tanks that are in service.

8.3 External Inspection of Out-of-Service Tanks

8.3.1 External Tank Bottom Inspection

Tank bottoms that rest on pads or on soil can be reliably inspected for soil-side corrosion using inspection technology developments such as magnetic flux leakage (MFL) bottom scanners or robotic inspection equipment. Tank bottom inspection has advanced from coupon cutting to a combination of UT and coupon cutting, electronic profiling or MFL scanning methods. When properly calibrated and operated to acceptable procedures, the probability of a better inspection exists with these newer technologies because much more of the surface area is examined and a better database with respect to bottom thickness measurements is available. With these developments, tunneling under or completely lifting a tank just for soil-side bottom inspection should normally be avoided, but these methods may be used when justified by other considerations such as a desire to coat the soil-side or the need to remove contaminated subgrade material or to install a release prevention barrier (RPB). It should be remembered that inspection of a tank by lifting may necessitate a hydrostatic test that would be unnecessary with other methods (see API 653, Section 12). As it is difficult to refill a tunnel properly, tunneling should be applied only to locations near the edge of the tank. Clean sand or washed gravel are the best types of fill material. Tank lifting allows 100 % inspection of the bottom from the external surface after adequate cleaning but can be relatively costly for a large diameter tank. Lifting does allow for blasting and coating (or re-coating if the existing bottom is coated underneath), as well as tank pad re-leveling and access for repair. Tanks that have been physically moved, jacked, or lifted should be either hydrostatically re-tested or subjected to an engineering evaluation.

8.3.2 External Pipe Connection Inspection

Inspection of pipe connections while a tank is out of service is essentially the same as when the tank is in service (see 8.2.5).

8.3.3 External Tank Roof Inspection

All roof plates should be checked for thickness, regardless of the external appearance. The inside surface of the roof plates may be susceptible to rapid corrosion because of the presence of corrosive vapors, water vapor, and oxygen. Figure 45 shows an example of roof corrosion that progressed completely through the metal. UT instruments should be used to check roof plate thickness. The same safety considerations as detailed in 8.2.10 regarding fixed roof inspection also apply to inspection of floating roofs, especially if external inspection is being performed with the tank is still in service.

On cone, umbrella, and similar fixed roof tanks; on pan floating roofs; and on the lower deck of pontoon floating roofs, the thickness testing should be accomplished before the bottom of the tank has been thoroughly cleaned, because considerable dust and rust may be dislodged from the inside of the roof. The interiors of the pontoons or double decks on floating roofs should be inspected visually. Metal thickness measurements should also be taken. For stability, some floating roofs have weighted (with concrete or sand) or hollow pontoons (sitting on top of the roof deck not penetrating to the product) that should be checked to ensure that they are watertight. If these pontoons become saturated with water, corrosion can occur and the roof may not function as intended. A bright, portable light (of at least 100 lumens) will be needed for this work.

Figure 45—Example of Sever Corrosion of Tank Roof

The condition of the roof rafters in fixed roof tanks can sometimes be checked through roof openings. Usually, the rafter thickness can be measured with calipers. Unless severe corrosion of the rafters is evident, these measurements should suffice. Coupons approximately 12 in. $\times$ 12 in. (300 mm $\times$ 300 mm) in size can also be removed from the roof to check for under-side corrosion and rafter condition. All coupons should be round or have rounded corners; no square-cornered coupons should be cut.

While inspecting tank roofs for corrosion, a search for leaks should be made, although the best way to find leaks in the roof is with the low-pressure air test discussed later in this document. If the drain is blocked, leakage may eventually cause the floating roof to sink. In addition, any leakage into the pontoon of floating roofs or through the bottom deck of double-deck roofs can eventually cause the floating roof to sink. Leakage in the roof deck or in the pontoons can also cause the roof to become unbalanced and possibly damaged if it hangs up on the shell.

Before an inspection of floating-roof seals, the seal details should be reviewed so that the operation is well understood. The points at which problems can occur will thus become more evident. All seals should be inspected visually for corroded or broken parts and for worn or deteriorated vapor barriers. Any exposed mechanical parts—such as springs, hanger systems and other tensioning devices, and shoes—are susceptible to mechanical damage, wear, and atmospheric or vapor space corrosion. Figure 46 shows one type of deterioration of a floating-roof seal.

Most floating-roof tanks are equipped with guides or stabilizers to prevent rotation. These guides are subject to corrosion, wear, and distortion and should be inspected visually. If the guides are distorted or the roof is no longer in alignment with these guides, the roof may have rotated excessively. The shell should then be inspected for deformation or other defects as previously outlined in this section.

Roof drains on floating-roof tanks can be designed in many ways. They can be simple open drain pipes or swing-joint and flexible-hose drains that keep water from contaminating the product. Roof drains must function properly; otherwise, certain types of floating roofs can sink or not function properly. Figure 47 and Figure 48 show the severe damage that can result. The damage in Figure 47 occurred while the roof was resting on its supports with excessive water load on top. The same type of failure can result from excessive snow, ice, or product loading. This kind of damage can be prevented by keeping the roof floating drain systems operating properly and by not landing the roof under such loading conditions.

When the tank is out of service, the drain lines should be inspected. Some drains are built such that the only possible way to measure wall thickness is by using calipers or by ultrasonic testing methods. Any movable joints in the drain lines should be checked visually for wear and tightness. The drain lines, including the joints, can also be tested for

Figure 46—Deterioration of Floating-roof Seal

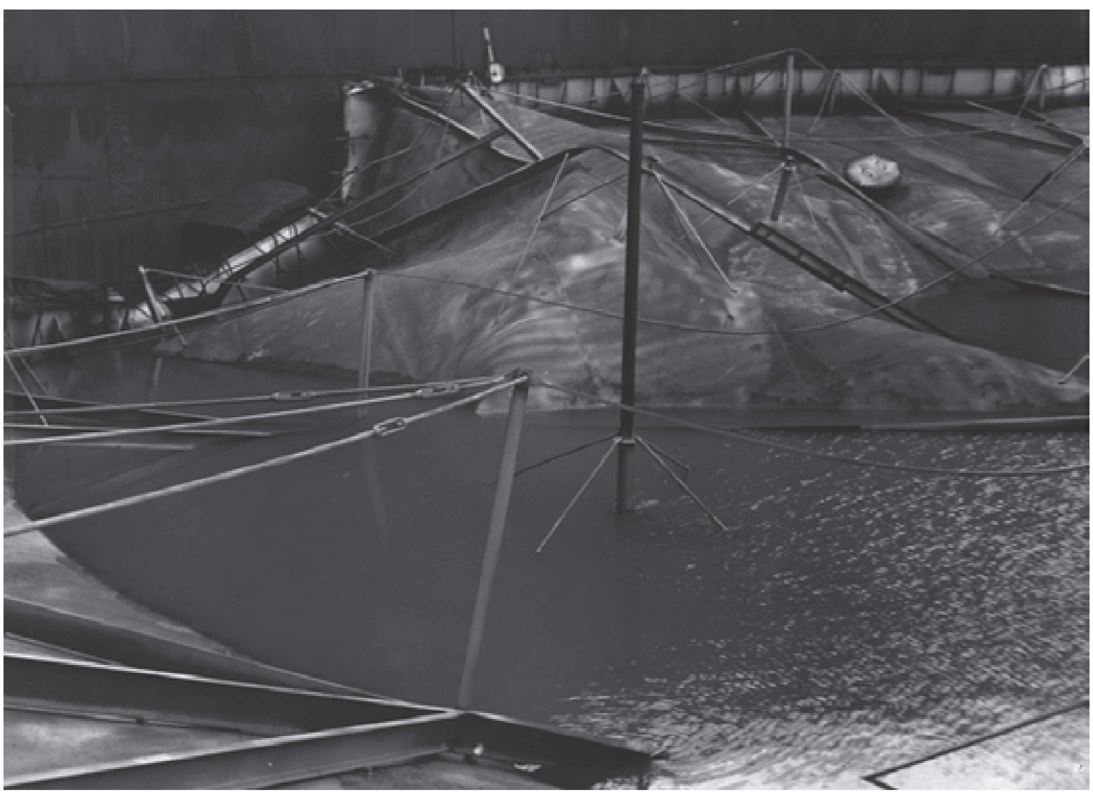


Figure 47—Collapse of Pan-type Roof from Excessive Weight of Water While the Roof was Resting on its Supports

Figure 48—Pontoon Floating-roof Failure

tightness by pressure testing with water. It has been found that a two-stage hydro-pneumatic test procedure is desirable. The first stage is a test at about 30 lbf/in.^{2} (207 kPa) gauge pressure for approximately $^1/_2$ hour to detect any leaks in the pipe, hose, or rigid joints. The pressure is then reduced to approximately 5 lbf/in.^{2} (34.5 kPa) gauge for another $^1/_2$ hour to test the tightness of the swing joints. Swing joints may be self-sealing at the higher pressure but will leak at the lower pressure if defective. The drain lines can also be checked for blockage at the completion of the pressure test by opening the drain valve and observing whether the test water flows out freely.

The design, construction, and physical condition of internal floating roofs, particularly the lightweight types (thin-skin aluminum and composite panel), should be taken into consideration prior to inspection. Planking may be required to walk on such roofs even if they are not corroded. If there are no roof drains, adequate inspection should be made to ensure that stored liquid does not leak onto the roof.

In addition to the appropriate inspections performed on floating roofs and cone roofs, the seals around columns and the ladder of internal floating roofs should be checked for leakage and condition. The ladder and columns should be checked for plumbness. The legs and leg sleeves should be checked for soundness and straightness. Aluminum floating-roof leg supports need to be adequately isolated from bare carbon steel as recommended in API 650, Appendix H to avoid corrosion by dissimilar metals.

8.3.4 Valve Inspection

All valves on the tank should be inspected when the tank is out of service. The first outside valve on all connections should be examined visually to ensure that there is no detectable leakage or deterioration. If leakage or significant deterioration is noted, consideration should be given to valve replacement while the tank is out of service. Valves can be refurbished if there is sufficient time during the out-of-service period but this option could affect the return to service schedule for the tank. Water draw-off valves should be inspected to determine their condition.

Bonnet and flange bolts should be examined to ensure that they have not significantly corroded and that they are tight and have proper engagement length.

8.3.5 Auxiliary Equipment Inspection

Pressure-vacuum vents and breather valves should be inspected in the manner described in 8.2.11.

Liquid level gauging equipment should be visually inspected. For float-type gauges, the float should be examined to find any corrosion or cracks and to ensure that it does not contain liquid. Cables and chains should be inspected for corrosion, kinks, and wear. Sheaves should be inspected to verify that they turn freely and are properly lubricated. Guides should be examined to ensure that they are free and not plugged. Any wooden parts should be checked for signs of rot.

If a pressure gauge is used on a tank, it should be checked to ensure that the pipe connection to the gauge is not plugged, that the gauge is operative, and that it is reading accurately. For ordinary uses, the gauge can be checked for reasonable accuracy by connecting it to a suitable source of pressure and a gauge known to be accurate. For calibration purposes, a deadweight tester or a calibrated test gauge should be used.

8.4 Internal Inspection

Internal inspections often require that the tank be out of service for entry and thorough internal visual inspection. As described in 8.1, physical entry is not always required to make an internal inspection. To minimize out-of-service time, the inspection should be planned carefully. As previously stated, all necessary equipment such as tools, lights, ladders, and scaffolding should be assembled at the site in advance, and arrangements should be made to have all necessary mechanical assistance available. For large, tall tanks, a tank buggy (a scaffold mounted on wheels) can be used as shown in Figure 49. Remotely controlled automated ultrasonic crawlers can also be used as shown in Figure 50. The necessity of adequate lighting for internal inspections cannot be overemphasized. The value of taking photographs or videotaping for inspection records should be considered.

8.4.1 Precautions

The tank must be emptied of liquid, freed of gases, and washed or cleaned out as appropriate for the intended inspection. See 8.1 as well as API 2015, API 2016, and API 653. Appropriate certification of the tank for personnel entry and inspection work should be part of the permit process. Many tanks that are cleaned after removal from service are not completely gas-free or product free unless particular attention is paid to areas where hydrocarbon build-up can be overlooked otherwise. Such areas include fixed roof support columns, floating-roof legs, and guide poles all fabricated from pipe or other closed sections without drainage holes and bearing pads or striker pads on the bottom that may have leak paths (exhibited by product weeping). Diffusers and other internal piping extensions inside the tank open to the product can retain product in the piping inverts and should also be completely drained and cleaned, and made otherwise safe prior to inspection work.

8.4.2 Preliminary Visual Inspection

A preliminary, general visual inspection is the first step in internal inspection. Visual inspection is important for safety reasons since the condition of the roof or top head and any internal supports should be established first. The shell and bottom should follow—in that order—for the preliminary visual inspection. Any evident corrosion should be identified as to location and type (pitting or uniform). The vapor space, the liquid-level line, and the bottom are areas where corrosion will most likely be found. Floating-roof tanks should be examined for loose or broken seal hangers and shoe bolt heads that can cause abrasive wear.

Following the preliminary, general visual inspection, it may be necessary to do further initial work before a detailed inspection can proceed. Any parts or any material hanging overhead that could fall, including large areas of corrosion (scale) products on the under-side of the roof, should be removed or otherwise made safe. In cases of severely corroded or damaged roof supports, it may be necessary to remove, repair, or replace the supports. Additional

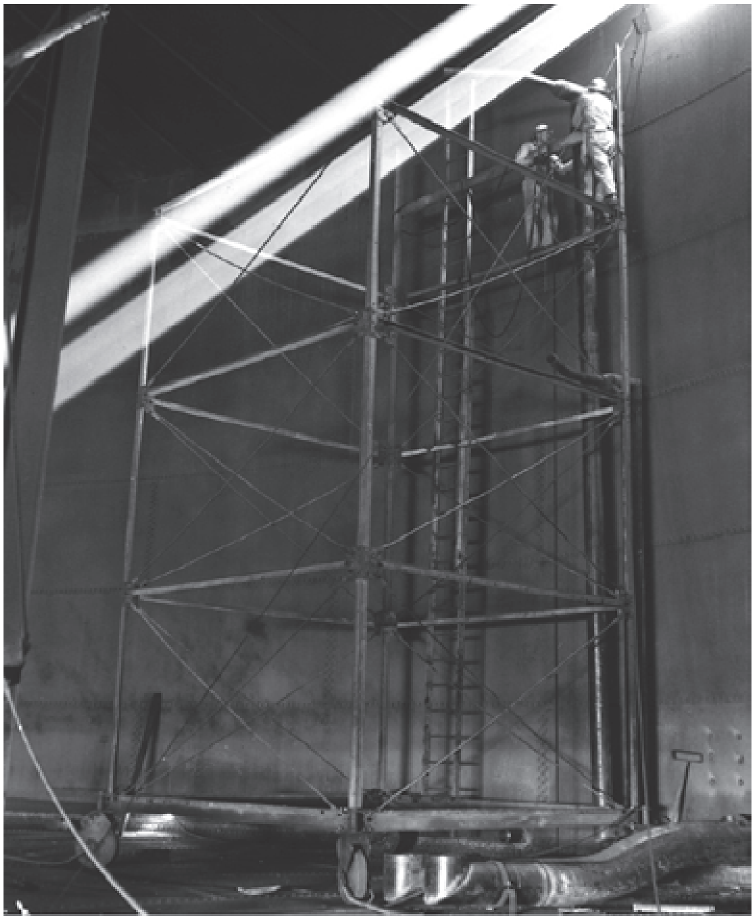


Figure 49—Tank Buggy Used for Inspection and Repairs Inside of Tank

Figure 50—Remote Control Automated Crawler

cleaning may be needed. If large areas are severely corroded, it may be best to have them water or abrasive-blasted. From a personnel safety or equipment operability standpoint, it may be even be necessary to remove light coatings of oil or surface rust. After these operations are completed, the detailed inspection can proceed under safer circumstances.

Inspectors should also be alert to accumulation of dry pyrophoric material (self-igniting when exposed to ambient conditions) during inspection. These accumulations may occur on the tank bottom, in the seal rim space areas, or on the top of rafters. Such accumulations that cannot be cleaned out prior to inspection should be kept moist to reduce the potential for ignition. See API 2015 and API 2016 for more information on controlling pyrophoric deposits.

8.4.3 Types and Location of Corrosion

Internal corrosion of storage tanks depends on the contents of the tank and on the material of construction. Severely corrosive conditions exist in unlined steel tanks storing corrosive chemicals or sour petroleum liquids. Corrosion will be uniform throughout the interior of such tanks but non-uniform corrosion may also be present. In sour refinery fluid service, the vapor space above the stored liquid can be an area of significant corrosion. This is caused by the presence of corrosive vapors, such as hydrogen sulfide, mixed with moisture and air. The vapor-liquid interface is another region that may be subject to accelerated corrosion, especially when fluids heavier than water are stored. Although these fluids are not common in refinery storage, water will float on the stored fluid and accelerate corrosion. Figure 51 shows an example of vapor-liquid line corrosion. In this case, the stored fluid was 98 % sulfuric acid (not corrosive to carbon steel at this temperature and concentration). Moisture collecting in the tank produced a weak (corrosive) acid in the upper layer of liquid, resulting in the deep grooving shown. When the stored fluid contains acid salts or compounds, they may settle to the bottom of the tank; and if water is present, a weak (corrosive) acid will form. Pitting-type corrosion can occur in the top of tanks directly under holes or openings where water can enter, at breaks in mill scale, and adjacent to fallen scale particles on the bottom.

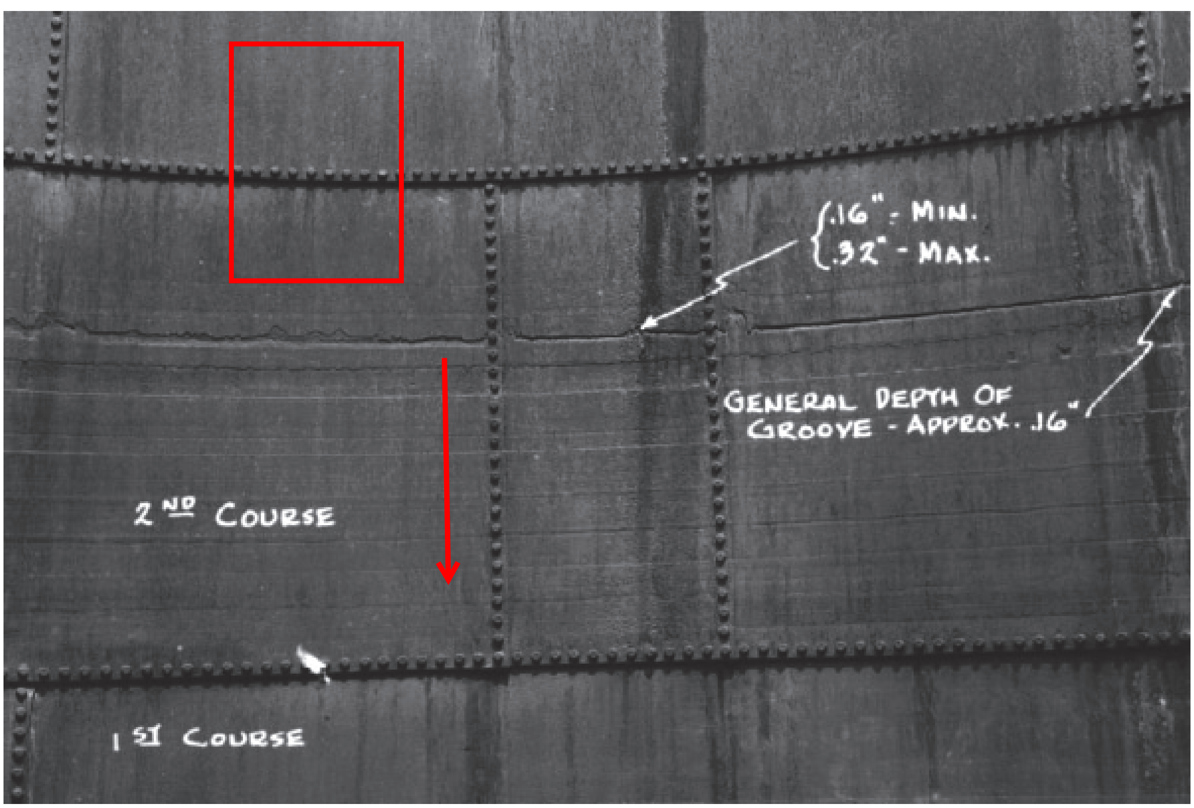


Figure 51—Example of Vapor-liquid Line Corrosion

Pipeline breakout tanks are often susceptible to accelerated corrosion behind floating-roof seals. Breakout tanks are typically used for the temporary storage of product prior to its injection into a pipeline system or to a final delivery location. Because storage is temporary, breakout tank roofs tend to be resting on legs the majority of the time. As the tank heats and cools, condensation, product residuals, and air trapped behind the roof seals will result in accelerated corrosion of the tank shell at the point where the roof seals normally rest. This type of corrosion is shown in Figure 52 and is typically identifiable as a band of corrosion extending around the tank circumferentially with a vertical height corresponding to the seal height. The severity of the band of corrosion may vary around the tank circumference depending on the location of the tank in relation to other tanks, the location of the sun, and other environmental conditions. The weld heat affected zone (HAZ) has been found to corrode at an accelerated rate in relation to the surrounding shell plate material. Tanks built to API 650 prior to the Seventh Edition of the standard may have been constructed with incomplete penetration of the circumferential shell weld seams. The HAZ corrosion may expose areas of incomplete fusion, resulting in areas where product can migrate within the interstice, presenting the possibility of flammable conditions.

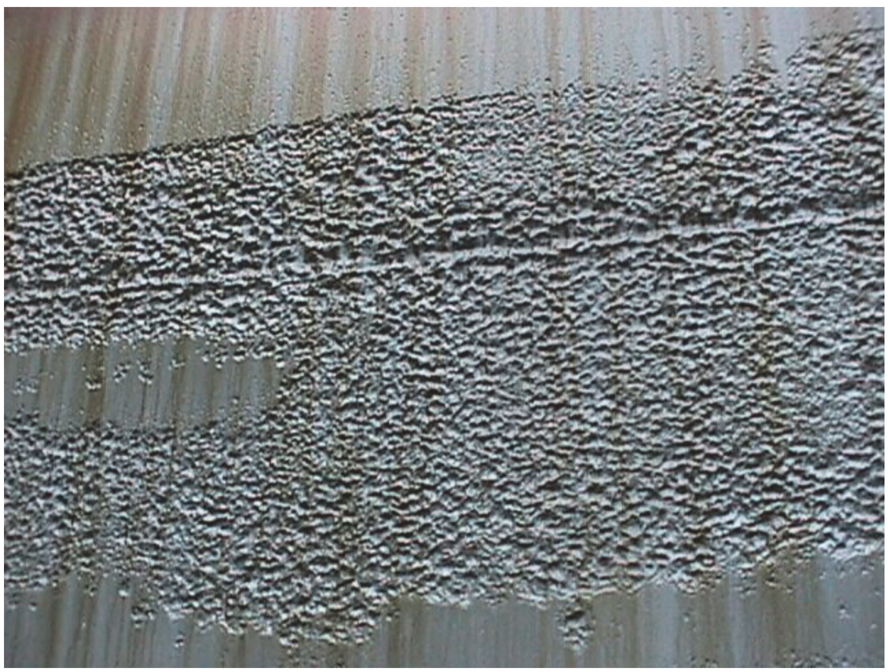


Figure 52—Corrosion Behind Floating-roof Seal

Among other types of deterioration that can occur on the shells of storage tanks are hydrogen blistering, caustic stress corrosion cracking, galvanic corrosion between dissimilar metals in close proximity, and mechanical cracking. These types of deterioration occur less frequently on the roofs and bottoms of tanks. Carbon steel that contains slag inclusions and laminations is more susceptible to hydrogen blistering. Caustic stress corrosion cracking may occur in tanks storing caustic products. Hot, strong caustic can also cause accelerated general corrosion. Areas of residual stresses from welding or areas highly stressed from product loading are most susceptible to caustic corrosion. Such corrosion thrives when the temperature rises above 150 °F (65 °C) and is most likely to occur around heating coil connections at the tank wall or at piping supports on the bottom.

If the insulation is not removed, or for low-temperature storage tank details that can make external inspection impractical, the shell can be inspected for external corrosion by ultrasonic area scans taken from the tank interior while out of service. This may help to identify areas of external shell corrosion that would otherwise be undetected.

8.4.4 Tank Bottoms

Good lighting is essential for a quality visual inspection. A minimum 100-watt halogen light is usually adequate, but more light is better. A brush blast of the bottom is necessary for uncoated bottoms or for coated bottoms where the coating has deteriorated to enable a good visual inspection to be performed and to ensure the effectiveness of other NDE techniques. The tank bottom should be inspected over its entire area to assess whether significant soil-side corrosion has occurred and whether there are manufacturing or repair defects. A range of NDE tools capable of rapidly scanning floor plate for metal loss are now in use across the industry. Magnetic Flux leakage (MFL) scanners are the most common but hybrid MFL/Eddy Current, Saturate Low frequency Eddy Current *SLOFEC) and well as ultrasonic based may also be used. On unlined tanks, many operators specify a brush blast or a commercial blast cleaning to accommodate MFL bottom scanning and the visual inspection. When suspect areas are located, a more detailed quantitative ultrasonic thickness or corrosion scan should be conducted. Typically, straight beam manual UT is satisfactory for quantifying soil-side corrosion; UT flaw detectors showing the full waveform display should be used for this measurement. Alternatively, multi-transducer ultrasonic inspection scanning devices with digital or analog displays can be used to detect under-side corrosion. Areas of signal loss in ultrasonic data need to be qualified further by additional inspection using methods such as manual A-scan, B-scan, or automated or shear wave ultrasonic testing. When ultrasonic scanners are used, the surface condition of tank bottom plates should be sufficiently clean to maintain adequate scanner accuracy during the inspection.

Experience demonstrates considerable variability in the effectiveness of tank bottom scanning inspection and UT prove-up. When conducted by qualified personnel, equipment, and procedures, scanning inspection can be highly effective. The owner/operator should consider the benefit in conducting a performance demonstration for personnel involved in tank bottom scanning and UT prove-up.

Statistical methods are also available for assessing the probable minimum remaining metal thickness of the tank bottom, and the methods are based on a sampling of thickness scanning data. The number of measurements taken for a statistical sampling will depend on the size of the tank and the degree of soil-side corrosion found. Typically, 0.2 % to 10 % of the bottom should be scanned randomly. The collection of thickness data is required to assess the remaining bottom thickness. In addition, the outer circumference next to the shell should be included in the statistical sampling. When significant corrosion is detected, the entire bottom should be scanned to determine the minimum remaining metal thickness and the need for repairs. A note of caution is in order about statistical methods for assessing the condition of tank bottoms. Soil-side corrosion tends to be localized, especially if the tank pad is not of uniform consistency or has been contaminated with corrosive fluids. A statistically adequate sampling of the bottom can be helpful in establishing the existence of corrosion that could result in a tank leak prior to the next scheduled inspection. Statistical sampling methods are used for both physical entry and robotic (see Annex A.5) inspection.

Pits can sometimes be found by scratching suspected areas with a pointed scraper. When extensive and deep pitting is located and measurements in the pits are necessary, the areas may be abrasive-blasted first, although it should be noted that this process can also create holes or open existing holes. The depth of pitting can be measured with a pit gauge or with a straight edge and steel rule (in large pits). An estimated depth can be found by extending the lead of a mechanical pencil as a simulated depth gauge. Seams of riveted tanks can be checked by running a thin-bladed scraper or knife along the riveted seam. If the seam is open, the scraper will pass into the opening and disclose the separation. Rivets should be checked at random for tightness. Rivet heads should be checked visually for corrosion (see 8.2.8.7). This may involve considerable scraping and picking to clean corrosion products from the rivet head. Consideration should be given to determining whether enough of the rivet head remains to last until the next inspection. Figure 53 shows a special case of severe corrosion near a tank bottom seam. The tank contents were acidic and were kept in motion with an agitator. This deterioration, a combination of corrosion and mixing erosion, would be further accelerated by the high stresses in the area of the riveted seam.

Depressions in the bottom and in the areas around or under roof supports and pipe coil supports should be checked closely. Any water that gets into the tank may collect and remain at these points, thereby causing accelerated corrosion. These support details should have seal welded bearing pads installed between the bottom and the support since they are areas that cannot be inspected properly otherwise. Low points such as sumps or sloped bottoms may

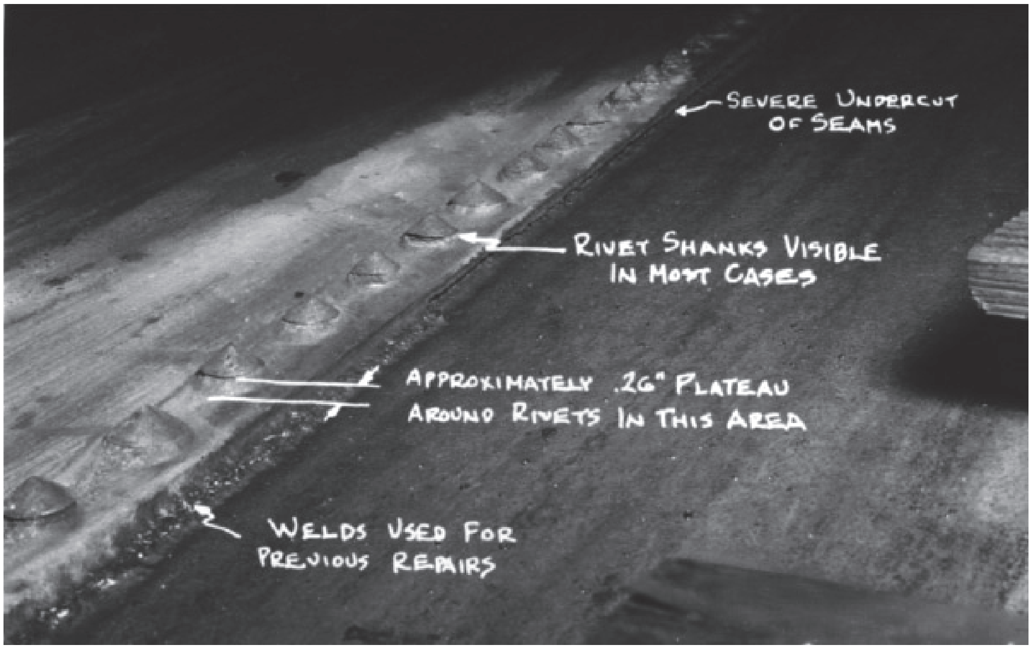


Figure 53—Localized Corrosion-erosion at Riveted Seam in a Tank Bottom

retain water and make the inspection difficult if not impossible. This condition should be corrected so that these areas, which are subject to higher than normal corrosion rates, can be carefully inspected.

If localized corrosion or pitting is present (from either the top-side or the under-side), single-point ultrasonic thickness measurements alone are usually not an appropriate method of assessing the condition of the tank bottom. In such areas, techniques providing broader inspection coverage—such as ultrasonic scanning, magnetic flux leakage scanning, and coupon removal—may be necessary. Automated ultrasonic devices can be utilized to give a more accurate picture of the soil-side condition of areas of the tank bottom plates. An example of extensive bottom corrosion is shown in Figure 54.

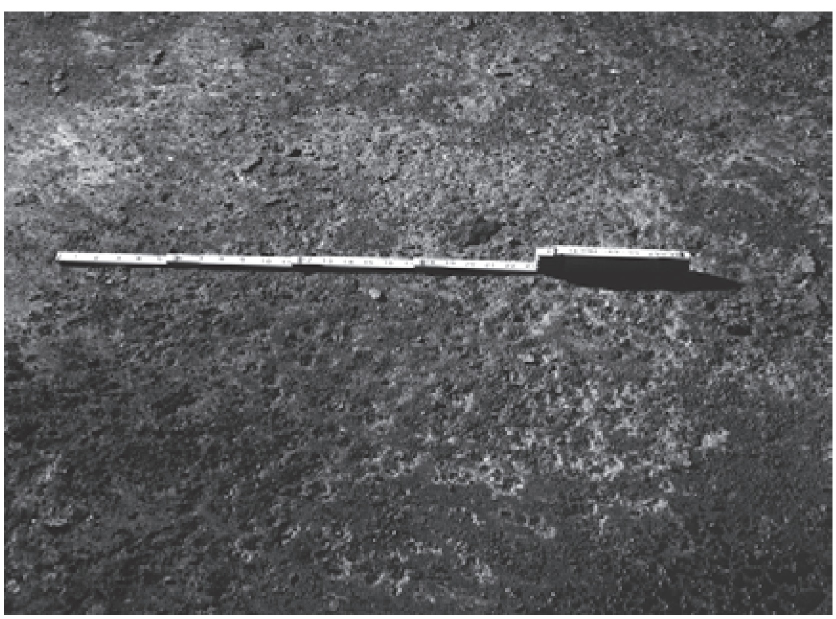


Figure 54—Example of Extensive Corrosion of a Tank Bottom

Unlined tank bottoms must be sufficiently clean for an effective visual inspection of plate surface areas and welds. MFL scanning equipment, when properly calibrated and operated per approved procedures, is capable of detecting soil-side corrosion, even through thin-film coatings.

Some scanning equipment can also operate effectively through thick-film coatings and reinforced linings. General metal loss and significant pitting can be effectively located using scanning equipment. Availability of such equipment has greatly lessened the likelihood of not detecting such soil-side corrosion. It should be noted that sharp, small, isolated pits may not be detected with this equipment.

Coupon removal, the prevailing method of determining the presence of soil-side corrosion previously, is not a reliable enough method for locating areas of localized soil-side pitting when compared to the alternative methods available today. Representative sections or coupons (minimum size 12 in. [300 mm] each way) may be taken to confirm the results of magnetic flux leakage or ultrasonic examinations. The increasing accuracy of magnetic flux leakage, ultrasonic scanning, and other automated methods makes coupon removal less useful, especially considering the time and expense associated with replacing the coupons. Coupons may be advisable in assessing the root cause of soil-side corrosion.

Water draw-off details are subject to internal and external corrosion and crack-like flaws. They are especially subject to crack-like flaws if they are cast iron, and they should be visually inspected to the maximum extent possible. Conversion to a water draw-off sump of the type illustrated in API 650, Figure 5.21 may be desirable under certain conditions. Internal low suction details should be examined for both internal and external corrosion.

The bottom should be checked visually for damage caused by settlement. Significant unevenness of the bottom indicates that this type of damage has occurred. If settlement is detected (internally or externally), the magnitude of the settlement should be measured. (API 653, Annex B, provides guidelines for evaluation of tank bottom settlement.)

API 653, Annex C, provides additional checklist entries for tank bottom inspection.

8.4.5 Tank Shell

The area of highest stress in flat bottom tanks is commonly at the shell-to-bottom joint detail and this area can be susceptible to corrosion as shown in Figure 55. This area should receive a close visual inspection for evidence of corrosion or other defects. If not coated (or if the coating is removed), this area can be further inspected by liquid penetrant or magnetic particle examination. It should be noted that a riveted shell-to-bottom joint using a structural angle detail is considered a mechanical joint, not a welded joint, and may not be suitable for certain types of examination.

Interior sources of shell seam (welded, riveted or bolted) leakage noted during external inspection should be investigated during internal inspection.

The shell should be inspected visually for signs of corrosion. The product service conditions will determine the areas of corrosion. The vapor space and operating liquid level are the areas most subject to corrosion. If the contents are corrosive, the entire shell can be subject to corrosion. Figure 56 shows an example of a tank shell corroded completely through because of corrosion. When significant corrosion is found, additional ultrasonic thickness measurements should be taken to supplement those measurements obtained from the outside.

When corroded areas of considerable size are located, sufficient thickness measurements should be recorded to determine the controlling thickness in accordance with API 653, Section 4.3.2.1.

While inspecting the bottom, the roof, and especially the shell of the tank for corrosion, the plate joints and nozzle connection joints should be inspected carefully for any evidence of cracking. A bright light and a magnifying glass will be very helpful in performing this work. If any evidence of cracking is found, a thorough investigation using magnetic particle, liquid penetrant, radiographic, or ultrasonic shear wave examination may be necessary. See API 653, Annex C for additional guidance on shell inspections.

Figure 55—Shell-to-bottom Weld Corrosion

Figure 56—External View of Erosion-corrosion Completely Penetrating a Tank Shell

8.4.6 Testing for Leaks

For tanks not provided with under-tank leak detection systems, a search for leaks through the bottom should be performed at intervals prescribed by API 653, in addition to a search for leaks through the shell. If the tank is to be hydrostatically tested during the course of the inspection, the hydrostatic test will be the best method for detecting shell leaks. If a hydrostatic test is not to be made, a penetrating oil (such as diesel or automobile spring oil) can be sprayed or brushed on one side of the shell plate in suspect areas and the other side can then be observed for leakage. Lower temperature will extend the time for oil penetration to become visible on the other side of the area being inspected. The liquid penetrant method used for finding cracks can also be used in much the same manner, with the penetrant applied to one side of the plate and the developer applied to the other side. For either method, approximately 24 hours may be required for leaks to become evident. Tank bottom leak detection methods are described in Section 9.

8.4.7 Linings

Special inspection methods may be needed when the inside surfaces of a tank are lined with a corrosion resistant material such as steel or alloy steel cladding, rubber or other synthetic fabric, organic or inorganic coatings, glass, or concrete (see API 652). The most important considerations to ensure that the lining is in good condition are that it is in proper position and does not have holes or cracks. With alloy steel or more rigid metal linings such as nickel and Monel, inspections should be made for leaks or cracks in the lining joints. A careful visual examination is usually required. If there is evidence of cracking, the liquid penetrant examination method can be used. The magnetic particle examination method cannot be used on non-magnetic lining material.

With rubber, synthetics, glass, and organic and inorganic linings, the general condition of the lining surface should be inspected for mechanical damage. Holes in the lining are suggested by bulging, blistering, or spalling. A thorough method of inspecting for leaks in such linings is the use of a high-voltage, low-current electrode that is passed over the nonconductive lining while the other end of the circuit is attached to the steel of the tank. This is commonly called a holiday detector. An electric arc will form between the brush electrode and the steel tank through any holes in the lining. Caution should be used so that the test voltage does not approach a value that might puncture or damage the lining.

To avoid mechanical damage to the linings, considerable care should be taken when working inside tanks lined with rubber, synthetics, glass, or organic or inorganic coatings. Glass-lined tanks are especially susceptible to severe damage that cannot be easily repaired. Glass-lined vessels should never be hammered or subjected to any impact on the inside or the outside because the lining can crack. It is advisable to paint them a distinctive color or to stencil a warning against striking them prominently on the external shell. It is important to keep spillage off the outside of glass-lined tanks. Corrosion from spillage can result in hydrogen penetration and cause defects in the glass liners (glass-lined tanks commonly contain materials that are more corrosive than can be stored in unlined or internally coated tanks).

Concrete linings are difficult to inspect adequately, primarily because the surface is porous. Concrete-lined steel bottoms are impractical to inspect unless the concrete is removed. A view of a lead roof lining is shown in Figure 57. Mechanical damage, breakage, spalling, major cracking, bulging, and a complete separation of the lining can be seen. Minor cracks and areas of porosity are more difficult to find. In some instances, they may be seen as rust spots on the surface of the concrete caused by steel corrosion products leaking through the lining. Corrosion behind the lining is possible where the concrete bond with the steel has failed.

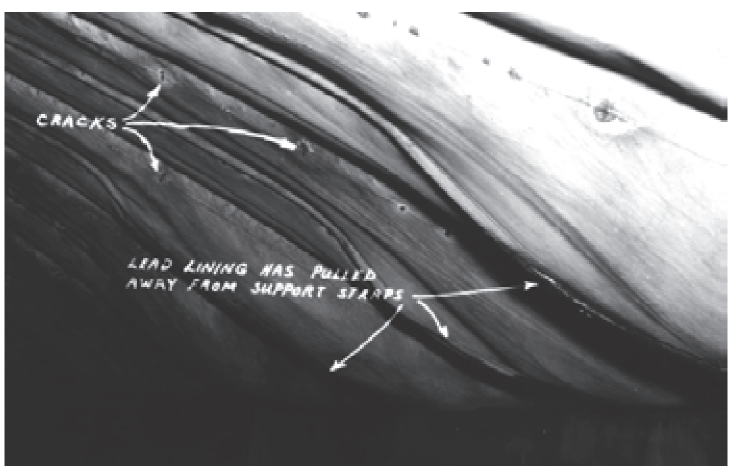


Figure 57—Deterioration of Lining on Roof of Tank Caused by Leaks in Lining

8.4.8 Roof and Structural Members

Ordinarily, a visual inspection of the interior roof plates, framing system and column supports is sufficient. When corrosion or distortion is evident or heavy under-side roof corrosion is indicated by external thickness measurements, access scaffolding should be erected so that measurements can be taken internally. If corrosion is noted on the roof and upper shell, then structural members may also be thinning, possibly at as much as twice the rate of the thinning of the roof or shell, since both sides of the structural members are exposed to the corrosive vapors. See API 653, Annex C, for guidance that is more detailed. Figure 58 shows an example of internal corrosion of roof plates and rafters.

When local corrosion has been found on the inside of the shell, any roof support columns should be checked closely at the same level. Transfer calipers and steel rules or ultrasonic thickness equipment may be used in measuring structural members. Measurements should be checked against the original thickness or the thickness of uncorroded sections. If corrosion or distortion of the members is evident, structural welds and bolting should be examined to determine the extent of the damage. Light hammer taps can be used to test the tightness of bolts and the soundness of structural members. Figure 59 shows the results of failure of roof supports (wooden supports are unusual in modern tanks but some such tanks may still exist).

The under-side of all types of floating roofs should be inspected for corrosion and deterioration not seen during the top-side inspection described in 8.3.3. Vital parts of some roof seals, such as the hanger supports of a mechanical shoe seal, can only be inspected from the under-side.

Figure 58—Internal Corrosion on Rafters and Roof Plates

8.4.9 Internal Equipment

Any internal equipment such as pipe coils, coil supports, swing lines, nozzles, and mixing devices should be visually inspected. Coils and supports should be checked for corrosion, deformation, misalignment and cracking. Except for cast iron parts, the coils and supports may be ultrasonically tested or hammer-tested. If wooden coil supports are used, they should be checked with a scraper or knife for rot, and the bottom should be checked for corrosion under the wooden supports. Consideration should be given to replacing wooden supports with metal supports. Coils should be tested hydro-pneumatically for leaks. Wet steam coils should be inspected for condensation grooving in the bottom of the piping coil using radiography or ultrasonic testing. If cracks are suspected in the nozzles or nozzle welds, they should be checked by the magnetic particle or liquid penetrant examination method. Figure 60 shows a typical installation of heating units in a tank, and Figure 61 shows an example of heating coil corrosion.

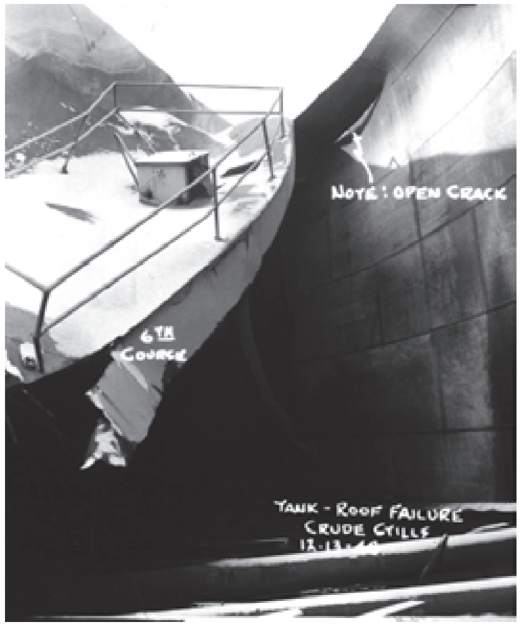


Figure 59—Failure of Roof Supports

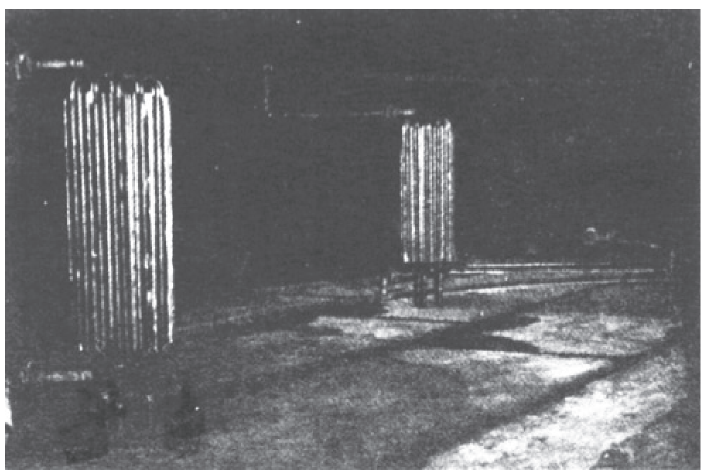


Figure 60—Fin-tube Type of Heaters Commonly Used in Storage Tanks

The swing lines of floating-roof tanks may be equipped with pontoons, rollers, and tracks. The pontoons should be hammer-tested and checked for leaks. The thickness of the pontoon wall can be measured by ultrasonic testing. The tracks and alignment rollers should be inspected visually for corrosion, wear, and distortion. The roof deck in the area of these tracks should be checked for bulging, which can occur if the swing line pontoons create an extensive upward thrust. Swing line rollers in contact with the under-side of internal floating roofs should also be inspected for damage or restricted movement. See API 653, Annex C, for more information.

The thickness of the tank nozzles and pipe walls should be measured with ultrasonic thickness instruments (especially if the connecting pipelines carry corrosive products or if there is any other reason to expect internal metal loss). Visual examination of a piping connection is usually made at the flange connection closest to the tank (by dropping a valve or unbolting the connection). Caliper measurements of the pipe can be made if a joint is opened. The caliper measurements will require emptying the line and blinding it at some point beyond the opened joint, emptying the connecting piping between the point of isolation and the open joint, and making that connecting piping safe and gas-free. Gasket surfaces of opened flanges should be checked for corrosion, and the flange faces should

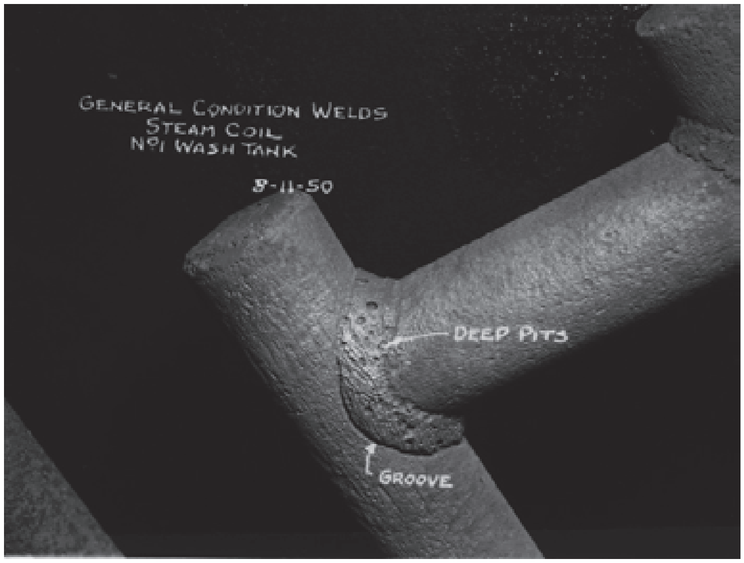


Figure 61—Example of Corrosion of Steam Heating Coil

be checked for distortion by using a flange square. Nozzle thickness can be calculated by measuring the inside and outside diameters or it can be determined by ultrasonic thickness measurement. As corrosion may be greater on one side of the nozzle, a visual or ultrasonic thickness check for eccentricity of the nozzle interior surfaces should accompany these measurements and calculations.

8.5 Testing of Tanks

When storage tanks are built, they are tested in accordance with the standard to which they were constructed. The same methods can be used to inspect for leaks and to check the integrity of the tank after repair work. When major repairs or alterations have been completed, such as the installation of a new tank bottom or the replacement of large sections of shell plate, the test requirements are specified in API 653, Section 12. If the repairs have not restored the tank to an equivalent full-height operating condition, the water height for the test should be limited in accordance with the lower strength conditions revealed during a re-evaluation of stored product height limitations.

The word testing, as used in this section, applies only to the process of filling the tank with a liquid or gaseous fluid, at the appropriate level or pressure, to verify the tank for strength or for shell or roof leaks.

Atmospheric storage tanks designed to withstand only a small (0.5 lbf/in.^{2} [3.5 kPa] gauge is typical) pressure over the static pressure of the liquid in the tank, are normally tested by filling with water. The lower portions of a tank are thus tested at a pressure that depends on the depth of water. All visible portions of the tank can be checked for leaks up to the water level. Leaks in bottoms resting on pads also can be detected if the test fluid seeps outside the tank perimeter where it can be seen visually. For certain high-strength and high-alloy steels, consideration should be given to the purity of the water for testing since contaminants such as chlorides can lead to the possibility of stress corrosion cracking (see API 571). Consideration should also be given to the notch toughness of the shell material at the air and water temperatures existing at the time of the test. A discussion of notch toughness and brittle fracture can be found in API 571 and in API 653, Section 5. If water is not available and if the roof of the tank is reasonably air tight or can be made so, a carefully controlled air test using air pressure not exceeding 2 in. (0.50 kPa) of water pressure may be applied. This type of test is of very little use as a strength test and is used only in inspection for leaks. For this test, indicator solution is applied to the outside surface of any suspect areas of the tank, shell, and roof weld seams, so that the air escaping through any leak path will produce bubbles indicating the leak location. Roof seams can be effectively vacuum-tested in the same manner. Very small leaks and some large leaks in welded seams may not be detectable using the vacuum box method.

Low-pressure storage tanks can be tested in a similar manner as atmospheric storage tanks but at slightly higher pressure depending upon their design (see API 620).

Carefully controlled pneumatic testing can be used when water or other suitable liquid is unavailable, when a tank would be unstable when filled with liquid, or when a trace of water cannot be tolerated in the stored product. If a tank is significantly corroded, pneumatic testing should be avoided. If it is necessary to use the method, caution should be exercised to avoid excessive stresses that could lead to brittle failure. Inspection for leaks can easily be made by applying an indicator solution to the outside weld seams of the tank and looking for bubbles.

8.6 Inspection Checklists

API 653, Annex C provides sample checklists of items for consideration when conducting external and internal inspections. These checklists, although relatively thorough, are not necessarily complete for all possible situations. Additionally, these checklists are not intended as minimum inspection requirements for all situations. They should be used judiciously by the inspector as guidance for issues and items to be checked during inspections, both internal and external.

9 Leak Testing and Hydraulic Integrity of the Bottom

9.1 General

Tanks that have impermeable foundations (reinforced concrete), under-tank liners, or tanks constructed with double bottoms, provide an inherent leak detection system which directs leaks to the perimeter of the tank where they can be visually detected in accordance with the leak detection provisions of API 650, Appendix I. These systems are collectively referred to as release prevention barriers (RPBs). RPBs are not typically retrofit with additional leak detection devices, cables or sensors since these would provide limited added value based upon industry experience. The owner/operator may elect to perform additional bottom integrity testing after repairs are made; the procedures that follow may assist in that assessment. While tankage that complies with a tank integrity program built upon API 653 generally has acceptable environmental performance, specific circumstances may warrant the use of additional measures to ensure that tanks are not leaking. When regulations or a risk assessment indicates the need for additional measures then the owner/operator can apply advanced technology leak detection systems such as those specified in API 334. Hydraulic integrity confirmation should be performed at intervals established in API 653, Section 4.

This section provides information on procedures and practices that may be used to assess the hydraulic integrity of the tank bottom. Except as specifically required in API Standard 653, all procedures identified here are recognized to be optional when used for attaining an enhanced confidence in the hydraulic integrity for a repaired or newly constructed replacement tank bottom. For those owner/operators that already have procedures for determining the suitability of the tank bottom, this discussion may serve as a reference when policy warrants a change in their methods.

Figure 62 identifies test procedures and summarizes operational issues that the tank operator should consider when assessing a suitable inspection strategy regarding the hydraulic integrity of tank bottom construction.

In cases where API 653 shows preference for specific procedures in specific applications, these cases are noted. It is beyond the scope of this document to assess the specific performance characteristics of one method compared to another, or to cover the impact of multiple testing with multiple technologies. More information on these topics has been published previously in such documents as API 334. As with any NDE method, it is the responsibility of the owner/operator to make that assessment. It is anticipated that leak test personnel (examiners) have qualifications consistent with API 653. Additional factors to consider include vendors and technologies that have been qualified by third-party testing agencies or owner/operators. These methods may be required by various regulatory agencies or companies and provide other effective ways to evaluate the needed qualifications.

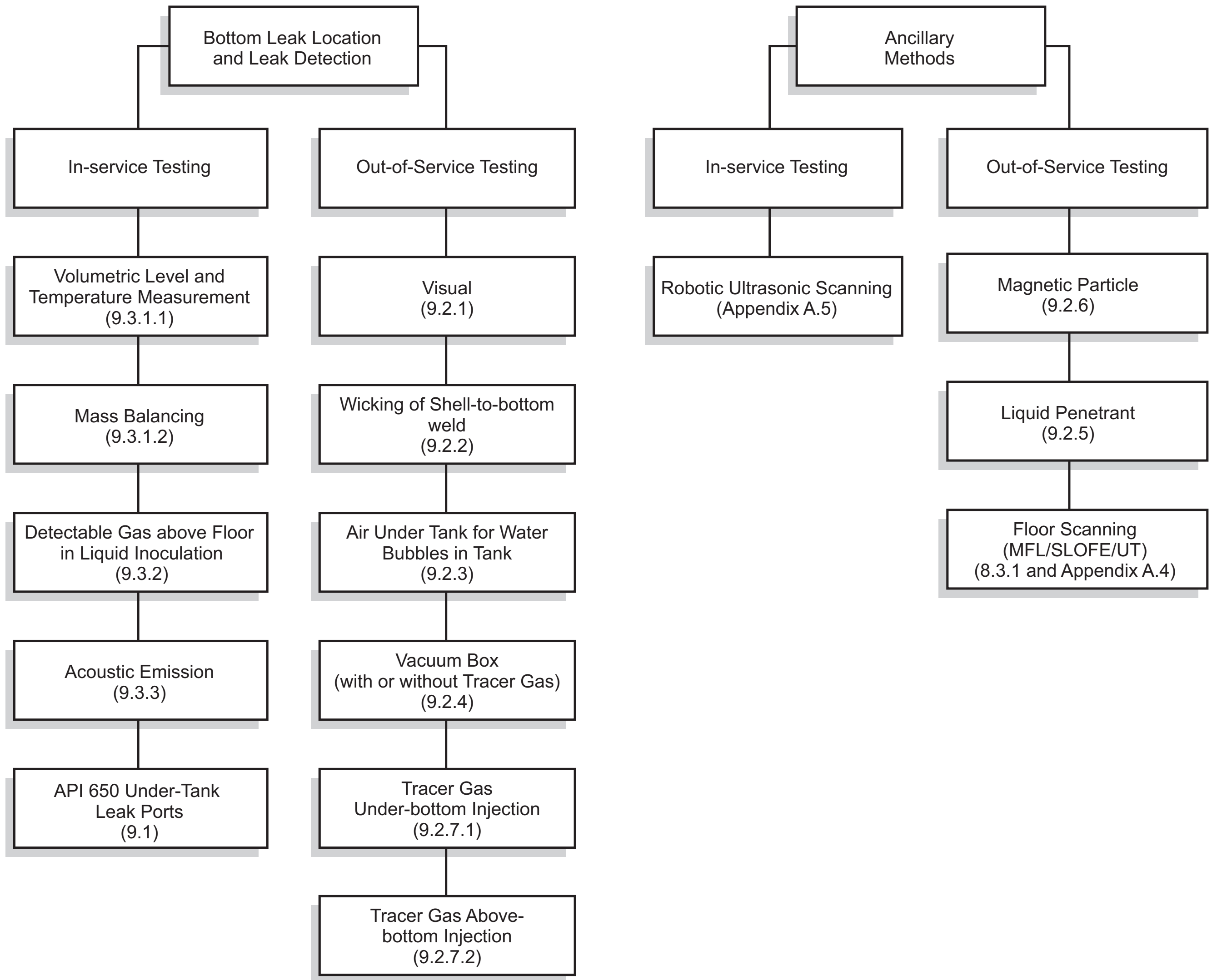


Figure 62—Hydraulic Integrity Test Procedures

When using information provided in this section, considerations for schedule, operational, economic and environmental characterizations should be reviewed. An owner/operator should be familiar with conditions under which the procedures can be used and in the case of developing technology, API 334 should be consulted. There are eleven procedures associated with determination of the hydraulic integrity of a tank bottom. Of this total number of procedures there are six that are conducted with the tank typically out of service during the API 653 internal inspection and another five procedures that are applied with the tank either partially or completely filled to its safe fill height with the service fluid.

9.2 Leak Integrity Methods Available During Out-of-Service Periods

9.2.1 Evaluation by Visual Examination

Visual inspection may be direct type when the surface is readily accessible to place the eye within 24 in. (61 cm) of the surface at an angle of not less than 30 degrees. The minimum illumination is 15-foot candles (25 lumens) for general viewing and 50-foot candles (100 lumens) for viewing of small anomalies. Visual inspection may be remote by using mirrors, cameras or other suitable instruments. The test would detect surface defects such as cracking, weld undercut, corrosion, dents, gouges, weld scars, incomplete welds etc. This method is applicable to all visually

accessible portions of the tank bottom. Additional details are described in API 650, Section 8.5. Section 8.2.2 of this RP provides additional description of leak location by visually detecting areas of soil-side wicking from an otherwise clean bottom.

9.2.2 Evaluation by Wicking Examination of Shell-to-Bottom Weld

This is a practical test because it provides information regarding the actual hydraulic integrity of the weld with a product less viscous than the product being stored. A leak could be easily located and repaired. The process of applying a highly penetrating oil or dye penetrant to one side of a weld (initial pass or completed weld as required by the applicable standard of construction or repair), then letting it stand for at least four hours (12 hours is preferred) and observing if it penetrates to the other side of the weld is called a wicking test (see API 650, Section 8.2.4.1 and API 653, Section 12.1.6). Personnel performing this test should have the same visual acuity required for performing other visual methods (see API 653 and ASME Section V).

9.2.3 Evaluation by Bubble Test Examination—Pressure

For this method, the inside surface of the bottom is coated with an indicator solution. Air at not more than 3 in. (0.75 kPa) of water pressure is injected by a hose under the bottom of the tank through the clay seal or through a drilled and tapped hole (or holes) in the bottom. The bottom is then inspected for bubbles, which will indicate any leaks. An alternative approach consists of pumping approximately 6 in. (150 mm) of water into the tank and then placing air at not more than 9 in. (2.24 kPa) of water pressure under the tank. Leaks will be evident if air bubbles through the water in the tank.

The effectiveness of these methods can be improved by tapping the entire bottom with an air-operated hammer. The sharp jarring of the bottom plates will frequently cause enough scale to pop out of pits to allow them to leak. When using 9 in. (2.24 kPa) of water pressure, the water must be pumped into the tank before air pressure is applied under the tank.

Figure 63—Vacuum Box Used for Testing Leaks

A variation on the bubble test method consists of pumping water under the tank to a depth of approximately 6 in. (150 mm) above the level of the highest point of the tank bottom and holding the water with the clay dam. Vents in the tank bottom are required to allow trapped air to escape. Leaks will then be evident as the water seeps through to the inside of the tank. This method can cause the tank pad to wash out or shift depending on its construction. It may also cause

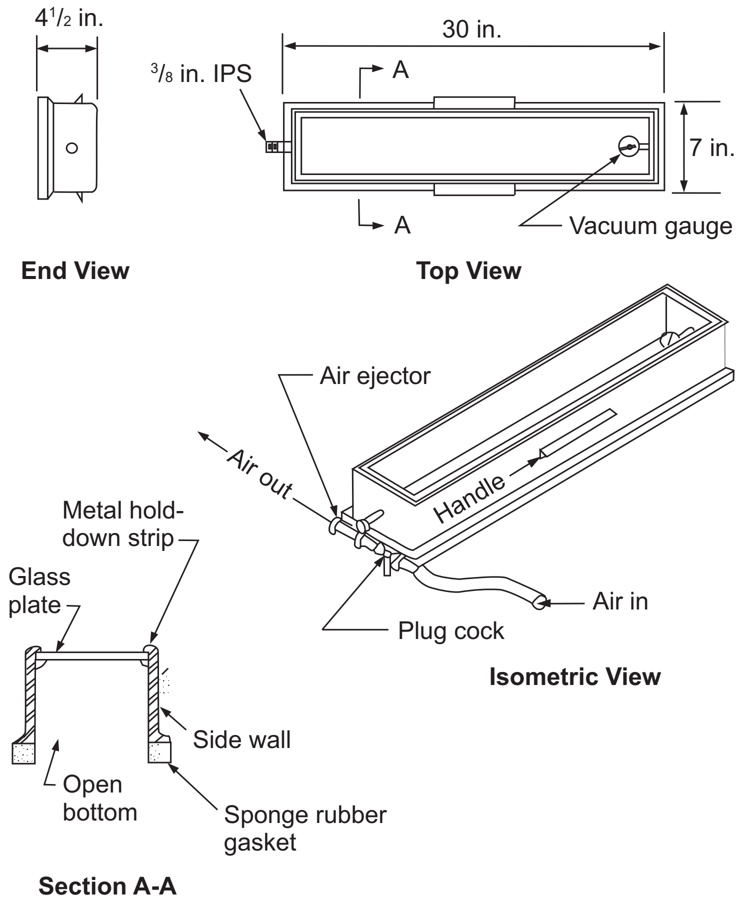


Figure 64—Vacuum Test Box Arrangement for Detection of Leaks in Vacuum Seals

the tank to float, and trapped water may later lead to accelerated corrosion. When using air under the tank, a considerable amount of plastering of the clay seal may be needed to build up the air pressure to the desired value.

9.2.4 Evaluation by Bubble Test Examination—Vacuum

Another method for finding leaks is the vacuum box method, which is particularly useful on the flat bottom of a tank but can also be adapted to the shell and the shell-to-bottom joint. An example of a typical vacuum box is shown in Figure 63 and Figure 64. In this method, the suspect area is first coated with an indicator solution. In cold weather, it is important that the leak-testing liquid be formulated for use at the temperature involved. The open side of the vacuum box with soft rubber gaskets attached is then pressed tightly over the area. A vacuum is developed inside the box by means of a vacuum pump or air ejector connected to the box through a hose. Leaks will appear as bubbles when looking through the glass top of the vacuum box. The method requires a minimum vertical clearance of 6 in. (150 mm) between the bottom and any obstruction for placement of device and accessibility to viewing the local area being examined. Additional details on test implementation are described in API 650, Section 8.6. Some inspection technicians offer an enhancement to this approach by supplementing the methodology with a detectable gas that has been pumped under the bottom (see 9.2.7.1). A detector for this gas is then attached to the vacuum box.

9.2.5 Evaluation by Liquid Penetrant

Liquid penetrant inspection is a test method that can be used to locate weld defects such as cracks, seams, laps or porosity that are open to the surface of the weld. Liquid penetrant is applied to the weld where it will enter discontinuities in the surface, primarily by capillary action. The excess penetrant is removed using water or a cleaning

agent. The weld is then allowed to dry and a developer is applied. The developer acts as a blotter to draw the penetrant out of the discontinuities back to the surface and as a contrasting background for the penetrant. The dyes are either color contrast (viewable in white light against a contrasting color developer) or fluorescent (visible under ultraviolet or black light). Discontinuities should show clearly as colored marks on a contrast background (visible light type) or a glowing fluorescent mark (ultraviolet light type). This inspection may be used on any weld. The test may be most useful in areas where other physical weld evaluations cannot be performed due to access limitations. Additional details on test implementation are described in API 650, Section 8.4. It is not required by API 650 or API 653, but is listed as an owner/operator-specified option.

9.2.6 Evaluation by Magnetic Particle Examination

The weld area to be examined is first magnetized and then ferromagnetic particles are placed on the weld. These will form patterns on the surface of the weld where there are distortions in the magnetic field caused by such weld discontinuities as cracks, seams, laps or porosity. The patterns are most evident for discontinuities located near the surface of the weld and oriented perpendicular to the magnetic field. The test is run a second time with the direction of the new magnetic field set up perpendicular to the old one in order to pick up discontinuities missed in the first pass. The magnetic particles are either color contrasting (viewable in white light) or fluorescent (visible under ultraviolet or a black light) type. The color contrast type is either wet or dry. Discontinuities should show clearly as colored marks (visible light type) or a glowing fluorescent mark (ultraviolet light type). The technology may be used on any weld. The test may be most useful in areas where other physical weld evaluations cannot be performed due to access limitations. Magnetic particle inspection is not required by API 650 and API 653, but is listed as an owner/operator-specified option.

9.2.7 Evaluation by Detectable Gas

9.2.7.1 Under-bottom Injection

Another method being used successfully is the injection of inert gas with a tracer element under the tank. An advantage of this method is that welded repairs can be made immediately with the inert gas under the bottom and a re-check can be made immediately after repairs.

The technology has been applied to existing, replacement and new tank bottoms. The tank must be emptied and cleaned prior to the testing. Tank cleaning by abrasive blasting will sometimes cause deep pits or very thin areas to begin leaking when scale or debris is the only material that was preventing leakage. This test method is best suited for uncoated plates or tank plates prior to coating or lining. This method is also well suited for determining the location of leaks in tank plates having a known or suspected leak.

Testing of tank bottoms using a detectable gas beneath the tank plates is accomplished by injecting the gas, which is lighter than air, beneath the tank plates in adequate amounts to allow dispersal over the entire under-side of the plate. Welding grade helium is a common gas used for this application. This test is performed by detectable gas injection through a standpipe or under-tank telltale piping system using a threaded coupling or other suitable connection. If the tank is not equipped with a leak detection system, or there is no way to inject detectable gas through the leak detection system, detectable gas injection may be accomplished by drilling and tapping holes in the tank bottom. Sampling ports are sometimes drilled in the bottom plates to confirm that the detectable gas has spread across the entire bottom. Once it has been confirmed that the detectable gas has dispersed across the tank bottom, detection instrumentation is scanned over the bottom from the product side. Instruments capable of detecting a few parts per million (ppm) of the tracer gas are then used for sniffing for leaks on the product side of the tank bottom as shown in Figure 65. The sensitivity of this test is dependent on the detectable gas concentrations (background) under the tank bottom and type of detection equipment used on the top surface that will help make tracer gas detection more successful.

This method of testing is applicable to 100 % of all bottom plates, welds, bottom-to-shell weld, patch plate welds, clip attachment welds, sump welds, weld scars, tear-offs, or other defects away from welds. Special attention should be paid to three-plate laps and areas of severe deformations.

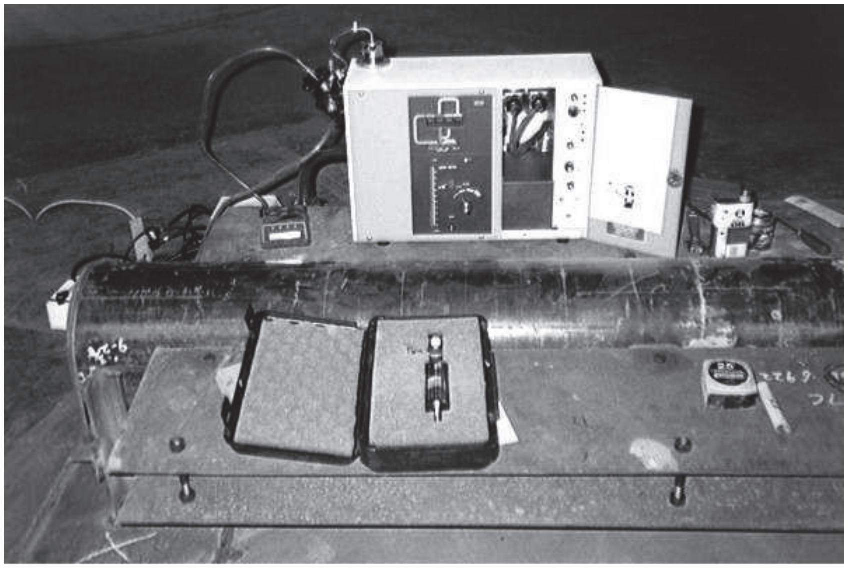


Figure 65—Helium Tester

If the subsurface under the bottom or the interstitial space between double bottoms is below the water table or saturated with water/product/liquid, the dispersal of detectable gas along the under-side of the bottom plates may be restricted or impossible. Consideration as to the feasibility of the test is required under these circumstances. De-watering or purging may be viable options to eliminate the problem.

In applying this test method, the inspector and/or technician should consider the design and construction of the bottom. If the bottom is anchored to a concrete pad, such as in a cut and cover or bunkered tank, compartmentalization of bottom plates or bottom sections may exist. In this circumstance, it may be necessary to drill numerous holes in a bottom to ensure complete dispersion underneath. In addition, there is a risk of over pressurization of the tank bottom and possible damage to, or failure of the anchoring system. Consideration as to the feasibility of the test is required under these circumstances.

9.2.7.2 Above-bottom Injection

The typical and preferred approach for implementing this leak test is to perform it with liquid in the tank as described in 9.3.2. Liquid loading has two primary advantages: 1) dispersion of the chemical marker is facilitated by the liquid; and 2) liquid loading will increase the probability of opening small cracks that might be closed otherwise.

The primary difference between implementing the technology without liquid loading compared to the approach outlined in 9.3.2 is the means of injecting the marker gas. In a liquid-free tank, plastic sheets are taped to the bottom and the marker gas is injected under the plastic. Sampling for gas in the under-tank well system is accomplished as described in 9.3.2. In addition, all of the limitations described in that section with respect to sampling and gas dispersion are applicable for the liquid-free implementation.

9.3 Leak Detection Methods Available During In-Service Periods

In the discussion that follows, the capabilities and characteristics of leak detection in the context of RPBs are not covered since these systems have been in use for many years and have proven to be effective and require little, if any, maintenance. The following section applies to advanced technology leak detection systems addressed by API 334 as typical examples. This section fully describes the key parameters that owner/operators should consider when selecting the appropriate technology for their application. The technology descriptions are presented here in summary form.

9.3.1 Evaluation by Leak Detection Systems Using Volumetric/Mass Measurement Technology

Leak detection systems based on volumetric and mass measurement technologies are an outgrowth of the automatic tank gauging industry and are a proven system for leak detection for underground fuel storage tanks (USTs). They have been in general use for USTs for several years and as such are widely accepted. Although they have been used commercially on ASTs with some success, third party validation testing is limited.

Both volumetric and mass systems operate on the principle of measuring the amount of liquid in a tank over time while eliminating or compensating for those variables in a tank that are unrelated to a leak. Any liquid loss or apparent volumetric/mass change not attributed to those variables may be considered a leak. These methods have the advantage of directly testing the hydraulic integrity of the tank bottom under near-operational conditions (with liquid in the tank and during the hydrostatic test prior to placing in service). There are several classes of systems, including:

a) volumetric level and temperature measurement;

b) mass measurement.

9.3.1.1 Evaluation by Leak Detection by Volumetric Level and Temperature Measurement

Volumetric level and temperature measurement technologies use sensors to measure the level of a liquid in the tank over time. There are two distinct implementations of this technology. In one mode, it is applied to a liquid level of at least 50 % of safe fill height; in the other mode, it is applied to a liquid height of a few feet (meters). This level is converted to volume using strapping charts. Additional sensors may be used to measure the temperature of the liquid (and tank shell) at various points. After eliminating from consideration the volume changes caused by noise (normally occurring events such as tank and fuel growth or shrinkage due to temperature changes) any remaining product volume drop may be considered a leak. The keys to volumetric level and temperature measurement are first, the measurement of the liquid level and second, the ability of the system to compensate for noise, primarily change in fluid and shell temperatures. More details on these technologies can be found in API 334.

9.3.1.2 Leak Detection by Mass Balancing

Mass measurement technologies use sensors to measure the pressure of a liquid in the tank over time by use of a differential pressure sensor. When conducting in-service leak tests, the owner/operator should consider the appropriate liquid fill height depending on the application and technology. Additional sensors are used to measure or compensate for the temperature drift of the differential pressure sensor. Other sensors are typically attached directly to the shell to assess diametric changes attributable to temperature change. After eliminating from consideration the volume changes caused by noise (normally occurring events such as tank growth or shrinkage due to temperature changes) any remaining product pressure drop may be considered a leak. The keys to mass measurement are first, the measurement of the liquid level and second the ability of the system to compensate for noise.

9.3.2 Evaluation by Detectable Gas Above-bottom in Liquid Inoculation (Chemical Marker Technology)

Detectable marker chemical (inoculate) has been applied to existing, replacement, and new tank bottoms. The tank is full or partially full of product or water prior to testing and may be used on coated plates, or tank bottom plates prior to coating or lining. This test is conducted without disruption of operations and may be useful during acceptance evaluation of a new tank or bottom by inoculating water just prior to the hydrostatic test.

Testing of tank bottoms using a detectable marker chemical in the tank is accomplished by injecting a volatile chemical into the receipt line, directly into the liquid, or the water draw-off line. The required concentration is a function of the following parameters:

a) mixing of the marker in the liquid;

b) leak detection threshold;

c) sensitivity of detection equipment;

d) composition of the soil under the tank;

e) wait time between inoculation and sampling.

Typically, an acceptable inoculation concentration is on the order of 1 to 10 parts per million (ppm). The marker must be compatible with product purity and comply with any regulations (e.g. non-ozone-depleting; approved for used in motor fuels or fuel for commercial aircraft, etc.).

If the subsurface of the bottom or interstitial space is below the water table or saturated with water/product/ liquid, migration of the marker chemical will be impeded. Two options are available:

1) de-watering or purging prior to sample collection; or

2) extension of waiting time for migration of inoculate in the liquid up to 60 days depending upon conditions and tank size.

Hollow tubes are installed under the tank bottom to extract air samples for analysis. A tank with secondary containment bottom details may have suitable detection tubes already installed. The under-tank gas collection system should be installed such that the termination point of each pipe covers the entire tank bottom, consistent with the anticipated leak detection threshold and the parameters listed. For many applications, acceptable leak detection performance can be realized with a tube layout so that no part of the bottom is over 20 ft (6 m) in lateral direction from any termination point.

The leak detection analytical equipment used to perform leak testing should be in calibration and capable of detecting concentrations consistent with the parameters listed previously. The marker gas detection equipment should be calibrated and tested for sensitivity and proper function throughout testing in accordance with the operating instructions.

9.3.3 Evaluation by Acoustic Emission Examination

Acoustic emission testing is based on the principle that liquid escaping through a fissure in the tank bottom or shell produces a detectable sound. The demonstration of this principle has shown that two types of sound are produced simultaneously. One type is detectable in the backfill material below the bottom. This impulsive sound extends beyond the audible frequency range and is the distinguishing characteristic signal upon which passive acoustic emission testing is based. The continuous hissing sound, even though it is generated by flow through a fissure, is considered, along with other detectable sounds, to be noise. For acoustic emission testing, noise is defined as any sound, continuous and/or intermittent, which is not a signal. The detection method includes the use of sound sensors that identify the appropriate sounds and therefore the presence of a leak. While this method cannot pinpoint the exact location of the leak, in some instances, when a number of sensors are used, the various signals can be triangulated to indicate the general location, so that more specific methods can be used to pinpoint its location. The acoustic emission test method is theoretically applicable for concurrently testing the parent metal plates, the bottom lap welds, and the sump(s), e.g. all tank bottom areas wetted by and under the head pressure of the tank contents.

Acoustic systems operate on the principle of detection by location. The basis for identifying a leak, a fissure in the tank bottom through which a fluid is leaking, is the point of origin of the signal. The frequency of an intermittent impulsive signal greatly depends on the condition of the backfill material. Porous materials such as well-drained sand could be expected to generate more impulsive signals per unit of time than cohesive materials like well-compacted clay if all other tank conditions were the same. The degree of saturation of water in the backfill also impacts the frequency of signals. If water or hydrocarbon product, possibly from an existing tank leak or possibly from natural characteristics of the foundation backfill and its general drainage, significantly displaces air immediately below the bottom plate at the location of a fissure, the impulsive signals may be reduced completely. The sources of noise, against which a signal must be discerned, include sounds initiated external to the tank as well as within the tank. The

effects of noise external to the tank can often be avoided by testing during quiet periods including low activity of nearby operations. Intermittent sounds initiated within the tank structure may be very similar to impulsive signals and must be accounted for in the reduction and interpretation of the collected data. Lining of the tank bottom prior to running this test may increase the chance that a leak path in a bottom plate or weld will be masked.

The type of sensor used in acoustic emission testing is an accelerometer, which converts sound energy into measurable electrical output. The sensors are clamped around the periphery of the tank shell, usually at evenly spaced intervals and near the bottom. In some implementations, at least one sensor may be placed at a higher elevation than the others to differentiate sounds initiated at the liquid surface or by the floating roof from sounds initiated at the bottom. In addition, the test operator may choose to cluster some sensors to account for reflected sounds created by echoes from internal piping and structural members. An echo, if undifferentiated from direct signals, causes errors in locating the origin of the signal.

For the acoustic test method to be able to indicate signals apart from noise, data collection algorithms and signal processing algorithms are used. The data recorder receiving all raw output from the sensors feeds these electrical outputs to a data collection algorithm to account for predictable unwanted sounds. The algorithm also is used for discrimination of multiple reflections from direct signals. The use of a high-performance algorithm complements the placing of sensors to account for the echo phenomena. The algorithm is configured for known general test conditions of velocity of sound in water or product, diameter of the tank, height of hydro-test water, and spacing of sensors on the shell. The algorithms will typically be able to discern signals and their point of origin.

The primary limitations of the technology concern the generation of the acoustic leak signal and distinguishing it from other sounds that will occur within the tank environment. The nature and condition of the backfill must be known, since it is an integral part of the acoustic system. Sludge and deposits that settle on the tank bottom may cause signal attenuation and must be taken into account. The sounds from a floating roof and its sliding seals, though nominally at rest, must be accounted for. Connected piping must be considered, as the noise of normal terminal operations such as pumping or valve actuation may be transmitted to the tank. Testing during quiet periods of low activity in near-by operations is often the most effective approach. A pre-test waiting period is recommended to accommodate and minimize noise from tank deformation and to allow for tank and foundation deformations that occur because of a change in the liquid height. Potential leaks in under-bottom piping require special attention in the placement of the sensors and may not be detected.

The effects of weather conditions such as wind and precipitation should be considered to minimize weather related noise. Tests are often put on hold or postponed during periods of adverse weather conditions. The following information should be part of the inspection record from any such acoustic emissions test:

a) date of test.

b) certification level and name of operator.

c) test procedure (number) and revision number.

d) test method or technique.

e) test results and tank certification.

f) component identification.

g) test instrument, standard leak, and material identification.

10 Integrity of Repairs and Alterations

10.1 General

Repairs and alterations to tanks can affect the strength, safety, or environmental integrity of the tank and thus require inspection after the repairs or alterations are completed. It is a good practice to make a visual check of all repairs and alterations to see that they have been done properly. In addition, some repairs and alterations may require other types of nondestructive examination as specified in API 653. This section will discuss some typical repairs and the recommended methods of inspection to assure the integrity of repaired or altered tanks. Not every defect or non-conformity will require repair. The decision to repair or not repair should be made by an engineer familiar with storage tank design, construction and maintenance issues.

10.2 Repairs

Before any repairs or alterations are made on tanks, the applicable codes, standards, rules of construction, and jurisdictional requirements should be known, so that the method of repair will comply with all applicable requirements. As a minimum, for guidance on repairs and alterations, refer to API 653, Section 9. All tank dismantling and reconstruction should be performed in accordance with API 653, Section 8 and Section 10, as well as the appropriate sections of API 650.

10.2.1 Repairs to Welded Tanks

Repairs made by welding on the bottom, shell, or roof of a tank should be conducted and inspected in accordance with API 653, Section 9, Section 11, and Section 12.

All crack-like flaws should be repaired unless a fitness-for-service (FFS) assessment (see API 579) or another appropriate evaluation indicates crack-like flaws do not need to be repaired in order to insure the integrity of the tank. Crack-like flaws in bottom or shell plates should be repaired by chipping, grinding, gouging or burning the flaw out entirely from end to end before welding. If several crack-like flaws occur in one plate, it may be more economical to replace the plate completely. Welded repairs of crack-like flaws should be inspected carefully to ensure that the cracks were completely removed, especially at the ends of the welded areas, using magnetic-particle or liquid-penetrant examination, as appropriate.

10.2.2 Repairs to Riveted or Bolted Tanks

Repairs can be made by riveting or bolting, using the procedures given in the original standards for riveted or bolted tanks. Repairs to these tanks may also be made by welding if the weldability of the steel is first confirmed by physical testing. At leaking rivet seams, rivets can be caulked, re-riveted, welded, or abrasive-blasted, and epoxy coated. Any epoxy coating or repair material should be allowed to cure as recommended by the manufacturer before the tank is returned to service. When parts or riveted seams are sealed by welding, the rivets and seams should be caulked for at least 6 in. (150 mm) in all directions from the welding. It should be noted that rivets and seams contaminated with hydrocarbons are difficult to repair by welding techniques. The weld repair may require several attempts, and in some cases, may not be successful in sealing the seam or rivet. Defective rivets can also be replaced by tap bolts, especially in the bottom plates where it is not possible to reach the under-side of the bottom. All repairs that involve caulking, riveting, bolting, epoxy coating, and partial welding should be inspected. The typical methods of inspecting repairs to riveted joints include visual, penetrating oil, hammer testing, and vacuum box or tracer gas techniques.

When making weld repairs to rivet heads or seams, special procedures that minimize distortion and residual stresses should be followed. These include:

a) use small diameter electrodes;

b) set welding machine at low amperage;

c) keep weld beads small;

d) use back-step bead application;

e) lightly ring-weld rivet heads adjacent to the weld area.

Consider using two-pass welds for rivets and seams that are to be seal welded, to allow for the possibility that the first pass will be poor due to hydrocarbon contamination.

In many cases, the preferred repair method for leaking seams and rivets is the use of an epoxy coating. This repair method removes the risk of creating additional leaks in adjacent seams and rivets as the result of shrinkage stresses associated with all weld repairs.

10.2.3 Bottom Repairs

For requirements on repairs to tank bottoms, see API 653, Section 9.10.

If complete tank bottom plates must be replaced, the replacement plates can be taken into the tank through a slot that is cut in the bottom shell course or they may be brought in through a door sheet and inserted into the slots from inside the tank or they may be lowered into the tank through access created in the fixed roof or external / internal floating roof.

When new bottoms are installed through slots, as illustrated in Figure 66, each sketch plate should be welded in place or securely wedged to the upper part of the shell plate before cutting the next slot. This will prevent the shell from sagging between slots. A perimeter layer of clean sand fill, metal grating, or a concrete pad should be installed under and at least 3 in. (76 mm) beyond the projection of the new bottom so that the shell is supported on the foundation through the new bottom.

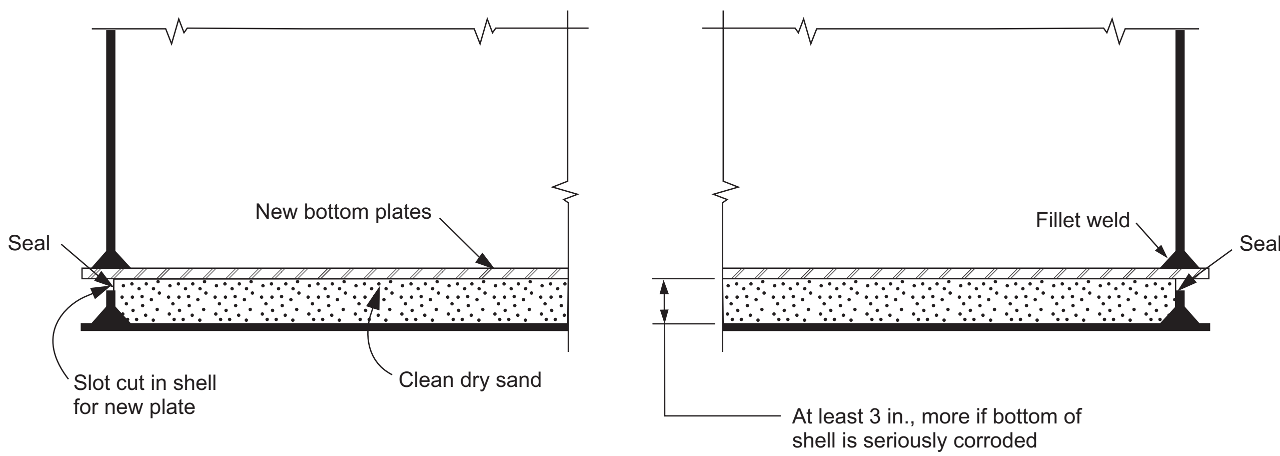


Figure 66—Method of Repairing Tank Bottoms

If the old bottom has been protected cathodically, or if cathodic protection is planned for a new bottom, the old bottom should be completely removed. If concrete is used as the spacer for a new bottom in conjunction with a non-conductive liner (release prevention barrier) then the old bottom may remain in place. If sand or aggregate is used as a spacer, anodes should be installed between the old and new bottoms in accordance with API 651 if the old bottom is not removed. For tanks retrofit with second bottoms and which use a concrete spacer, a cathodic protection system is not necessary for either the old bottom or the new bottom, even if the tank was previously protected by cathodic protection. This is because the old bottom no longer serves as the release prevention barrier but the elastomeric liner that is installed electrically isolates the old bottom from the new bottom and the concrete is not considered corrosive as well as being better drained than the original foundation.

Nondestructive examination requirements for bottom repairs and alterations are given in API 653, Section 12 and are summarized in API 653, Annex F, as well as API 650. When entire tank bottoms are installed, the NDE requirements are the same as for new tanks constructed to API 650. These requirements include:

a) visual examinations (F.2.1.c);

b) magnetic particle and/or liquid penetrant examinations (F.3.1.d and F.3.2);

c) vacuum box testing (F.5.1.a and F.5.1.b);

d) tracer gas testing (F.6.1);

e) radiographic examinations (F.9.1.e and F.9.1.f);

In addition to conducting the above examinations as appropriate, the hydraulic integrity of tank bottoms that have undergone repairs or alterations may be further assessed by applying the testing procedures contained in Section 9.

10.2.4 Shell Repairs

10.2.4.1 The requirements for shell repairs and alterations outlined in API 653, Sections 9.2 to 9.9 should be followed. Since the reinstallation of door sheets can be difficult for even experienced tank specialists, the following procedure is suggested.

a) Locate the door sheet where the bottom plate is reasonably level for a distance of at least 5 ft on either side of the door sheet vertical seams. This will prevent differential bottom settlement due to load transfer when the door sheet is removed.

b) Make the door sheet cuts so that the vertical and horizontal weld joints meet the weld spacing requirements in API 653, Section 7. Leaving a shell lip by making the bottom door sheet cut above the shell-to-bottom weld can provide sufficient stiffness if bottom buckling is a concern. Alternatively, the bottom door sheet cut may be made at the shell-to-bottom joint. This method may require a hydrostatic test of the tank following completion of the repairs.

c) Provide reinforcement to the shell around the door sheet cutout as required to prevent distortion of the shell from the unsupported dead load or wind loads. This reinforcement can be structural shapes welded to the shell.

d) After reinstalling the door sheet, radiograph the weld in accordance with API 653, Section 12.2.

10.2.4.2 Nondestructive examination requirements for shell repairs are presented in API 653, Section 12 and are summarized in API 653, Annex F. These requirements include:

a) visual examinations (F.2.1.a to F.2.1.f);

b) magnetic particle and/or liquid penetrant examinations (F.3.1.a to F.3.1.h and F.3.2);

c) ultrasonic examinations (F.4.1.a to F.4.1.d);

d) vacuum box testing (F.5.1.a);

e) diesel oil testing (F.7.1.a);

f) air leak testing (F.8.1);

g) radiographic examinations (F.9.1.a to F.9.1.d and F.9.1.f and F.9.1.h).

10.2.5 Roof Repairs

Roof plates can usually be replaced in the same manner in which they were installed when originally constructed. For further guidance, see API 653, Section 9.11, Section 9.12, and Section 9.13.

Nondestructive examination requirements for roof repairs and alterations are presented on API 653, Section 12 and are summarized in API 653, Annex F. These requirements include:

a) visual examination (F.2.1.c);

b) magnetic particle and/or liquid penetrant examinations (F.3.1.d);

c) vacuum box testing (F.5.1.c);

d) diesel oil testing (F.7.1.b).

10.3 Special Repair Methods

When deep pits in tank plates are not closely spaced or extensive and thus do not affect the strength of the tank, they may be repaired or filled by a number of methods. Filling with air-hardening adhesive-to-steel epoxies may be suitable if it will not be affected by the tank's contents. Any other material of a putty-like nature that hardens upon drying can be used for temporary repairs; such material must be able to tolerate the tank's contents in addition to making a tight bond with the steel plate. In all cases, the pits should be cleaned thoroughly, preferably by abrasive blasting, and then filled as soon as possible.

The application of epoxies and other thermo-setting resins can provide valuable corrosion protection for storage tank shells, bottoms, roofs, and pontoons. Combined with fiberglass cloth, they provide effective repairs for bottoms, roofs, and pontoons, as well as other low-stress members. See API 652 for more information on lining repairs.

Leaks in roofs can be repaired by soft patches that do not involve cutting, welding, riveting, or bolting of the steel. Soft patches can be made from a variety of materials, including rubber, neoprene, glass cloth, asphalt, and mastic or epoxy sealing materials; the choice depends on the contents of the tank and the service conditions. The patching is applied in much the same manner as similar patching would be applied to the roof of a building. The patches may be applied when the tank is in service, if proper safety practices are followed. Figure 67 and Figure 68 show a patch and a complete coating, respectively.

Figure 67—Temporary "Soft Patch" Over Leak in Tank Roof

Figure 68—Mastic Roof Coating

It should be noted that if large areas of patching are used then consideration to personnel safety and the possibility of fall-through becomes likely for persons working on roofs repaired in this manner. Also, be aware that should parts of the repair materials be dropped into the tank while making these repairs, or while the tank is in service, this can lead to hazards if these parts enter piping and pumping systems and cause blockages, seal failures and/or fires or other process related problems. These repairs should be inspected at a frequency that is higher than conventional permanent repairs. Soil foundations that have washed out or settled under the bottoms of atmospheric storage tanks can be repaired by pumping sand, drilling mud, clay, lean concrete or similar material under the tank. Material can be pumped through holes cut in the tank bottom. In some cases, it may also be necessary to raise the tank with jacks, as shown in Figure 69. It should be noted that while these repairs are possible, they may cause problems in some cases because of localized pressure from the pumping or grouting process, resulting in yielding and bending of bottom plates in an uneven, local mode. The experience of the contractor performing the work may be a significant variable.

Figure 69—Tank Jacked Up for Repairing Pad

11 Records

11.1 General

Good records form the basis of an effective inspection program and are the key component to ensuring that accurate evaluations and inspections are carried out in the future. Accurate and complete records are used to predict when repairs and replacements may be needed, reducing the potential for safety and environmental hazards. Accurate records may also be used when information is needed for new tank specifications.

11.2 Records and Reports

A complete record file should consist of at least three types of records: a) design and construction records, b) repair/ alteration records, and c) inspection records. Refer to API 653 for a description of these types of records. Records should be maintained throughout the service life of each tank and should be updated to include new information pertinent to the mechanical integrity of the tank. Inspection reports should also document:

a) the date of each inspection;

b) the date of the next scheduled inspection;

c) the name of the person who performed the inspection;

d) a description of the inspection performed;

e) the results of the inspection;

f) any repair recommendations, including the location, extent, and reason for repair;

g) records that recommended repairs have been completed.

The following is additional information or documentation that may also be included (but not required):

a) tank identification number or other label;

b) description;

c) contents and specific gravity;

d) design operating temperature;

e) overall dimensions;

f) materials of construction;

g) design codes and standards used;

h) nozzle schedule;

i) corrosion allowance;

j) post weld heat treatment requirements and reports;

k) type of supports;

l) painting and insulation requirements;

m) fabrication documents such as welding procedures and welder qualifications;

n) code calculations;

o) manufacturer's data reports;

p) reports on periods of abnormal operation (e.g. process/system upsets such as elevated pressures, high temperatures, or fluid concentrations outside the operating limits that might affect mechanical integrity of the tank) including an analysis of the vessels integrity due to the abnormal operation;

q) identified deficiencies that were not repaired (i.e. they did not affect the tank's required integrity);

r) fitness-for-service assessment documents (see e.g. API 579).

Any method that retains the data and documents the associated results and conclusions of the inspection is an acceptable form of record keeping. This does not necessarily require an all-paper or all-electronic media system. For example, video equipment and verbal discussion may be an acceptable format when used correctly. Any combination of various media may be used as long as it supports the purpose of the inspection.

Inspection records should be readily available. In situations where records are kept in a remote or central location, at least one complete set should be maintained at the facility.

11.3 Form and Organization

The inspection reports required by API should be organized in a convenient manner and as requested by the owner/operator. This usually means an executive summary up front, a statement as to whether the report is an external or internal inspection and other relevant information such as the facility name, the tank number, etc.

The report should clearly breakdown the following categories of recommendations.

a) Those areas that require immediate repair or change that are mandatory in order to maintain the continued safety, health and environmental concerns of the facility and that should not be delayed.

b) Those areas that should be repaired to extend the tank life that may fail before the next internal inspection.

c) Those areas that can be deferred until the next internal inspection without jeopardizing health, environment or safety and that the owner/operator wants to defer.

d) Those items that are strictly non-threatening areas of concern such as cosmetic issues, settlement that is within the API 653 tolerances.

All recommendations should have supporting calculations, photos and rationale included in the final report.

Annex A
(normative)

Selected Non-destructive Examination (NDE) Methods

A.1 Ultrasonic Thickness (UT) Measurement

Ultrasonic testing may be used in conducting inspections. In the context of tank inspection, it is typically used for thickness determination. It should be noted that UT is not required since any method that establishes corrosion rates may be used. When UT is applied and the corrosion rate is not known, then the maximum interval between inspections is specified in API 653, Section 6. Other methods that may be used for determination of corrosion rates include similar service, corrosion coupons, use of more conservative corrosion rates by substituting bottom corrosion rates for shell corrosion rates, etc.

It is recommended that the ultrasonic instrument have an “A Scan” display with a digital readout. UT measurement should be performed using a transducer with characteristics appropriate for the particular test to be performed.

Dual-element transducers are frequently selected, and they are available with many different operating ranges. Dual-element transducers may have the ability to measure thin sections from 0.050 in. to 1.000 in. (1.3 mm to 25 mm). The limitations of transducers that should be recognized are that their range is finite and that the transducer frequency must be high enough to measure thin sections accurately. Holes in the material or sections of less than 0.050 in. (1.27 mm) will provide either no reading or a false reading when measured with too low a frequency.

Further, if the material being tested is coated, procedures must be employed to account for the coating thickness. The dual-element transducer will read the thickness of the coating in addition to the thickness of the base metal. The effect of the coating on the overall thickness measurement will depend on the difference in the velocity of ultrasonic wave propagation between the base metal and the coating material. This difference may be significant in some cases. For example, epoxy coatings have a wave velocity approximately half that of the steel, therefore the ultrasonic tool will measure 0.015 in. [15 mils] of epoxy coating as 030 in. [30 mils]) of steel. Selection of a single-crystal transducer operating in the so-called echo-to-echo mode can prevent this coating thickness error. However, the single-crystal transducer has poor resolution for small diameter deep pits. Many echo-to-echo measurement devices now generally available eliminate the need to compensate for the coating thickness during measurement. Once properly calibrated, the multi-echo technique produces direct readings through coatings up to approximately 0.080 in. to 0.100 in. (80 mils to 100 mils) thick without loss of accuracy. The echo-to-echo mode is sometimes difficult to use for measuring the thickness when the backside is heavily corroded because the loss in signal caused by the corrosion may prevent resolution of the second back wall echo. Currently, some UT transducers and gauges for thickness measurement offer the ability to measure coating thickness and remaining wall thickness simultaneously. UT thickness measurements on tank bottoms, shells, and roofs should carefully distinguish between thickness loss and mid-wall laminations. Standard thickness transducers when used with UT flaw detectors and or thickness gages can be used to view the “A Scan” which can be effective for this purpose.

A.2 Ultrasonic Corrosion Mapping

Many automated ultrasonic corrosion mapping units that enable areas to be scanned with high-resolution repeatability are available. Typical automated UT equipment as shown in Figure A.1 is used for this purpose. Selection of the correct transducer size and frequency is critical to test resolution. The American Society of Mechanical Engineers (ASME) recommends 10% minimum overlap for readings based on the transducer diameter. Large diameter transducers will not find small diameter deep corrosion pits. Some scanning techniques can illustrate very thin sections or holes as dropout regions in the data plot. Phased Array Ultrasonics is now used for thickness mapping and provides ultra high data point density which helps in detection, characterization and discrimination of mid-wall anomalies from loss of wall thickness.

A.3 Ultrasonic Angle Beam Testing

Angle Beam Ultrasonic (Shear and High Angle L Wave) inspection can be used to assist in the discrimination between laminations and inclusions in material. Automated angle beam ultrasonic testing is especially effective for this purpose. The most general application of angle beam transducers is to detect defects in butt-welded joints, usually in lieu of radiography.

A.4 Floor Scanning Inspection of Tank Bottoms

Tank bottom scanning has become a commonly used technique to effectively evaluate a large portion of the tank bottom for both top or product side corrosion, and bottom or soil side corrosion. Typically, a floor scan can cover a majority of the tank bottom, excluding areas adjacent to welds and other obstructions. While this varies, typically 80% of the floor can be successfully inspected, which can be increased using complimentary techniques. Since the inception of magnetic flux leakage (MFL) scanners, the ability to scan a large portion of tank bottoms has been available. This is a major improvement in inspection capability for tank bottoms because of the random nature of tank bottom under-side corrosion. Additionally, a number of other inspection technologies have become available such as, low-frequency eddy current, remote field eddy current, and partial saturation low-frequency eddy current technology. See Figure A.2 for an example of a bottom scan unit. The user should make sure that the scanner is calibrated properly and has a validation and/or calibration test plate, which will ensure that the test area is inspected uniformly over the width of the scanning head. A primary advantage of these tools is the ability to detect product-side pitting, soil-side corrosion, and holes in the tank bottom in an efficient and economical manner.

It should be noted that simply scanning over the area does not ensure detection of all metal loss as all systems have detection thresholds. The owner should determine what the minimum detection threshold is a factor this into the overall assessment. Furthermore, of the systems require some additional inspection to quantify detected flaws. Typically, an ultrasonic examination method is used for such prove-up work. Section 8.4.4 provides additional details. Figure A.3 shows a typical UT bottom scrub area scan to establish the extent of soil-side corrosion. There can be considerable variability on the quality of these inspections. Industry experience shows they can be highly effective when operators with the proper training and experience use machines with suitable detection capabilities. Most scanners and procedures require operators to optimize sensor and magnet standoff from the bottom. Moreover, they must determine the suitable sensitivity settings. Experience shows that these sensitivity settings should be optimized on the specific tank under examination for the anticipated corrosion morphology. Follow-up ultrasonic examinations are critical for an effective electromagnetic bottom scan inspection. Performance demonstration testing of the operators can increase the probability of detecting and accurately sizing corrosion.

A.5 Robotic Inspection

Tools for internal tank inspection used while the tank is in service have been developed. These robotic crawler devices are designed for total immersion in liquids and have been successful in providing ultrasonic thickness information on tank bottoms in clear finished product storage such as gasoline, naphtha, jet fuel, No. 4 and No. 6 fuel oils, condensate, and some crude oil. This equipment needs to be used under carefully controlled circumstances and within API safety guidelines for work on tanks in service. See Figure A.4 for an example of a robotic inspection tool. The technology has been utilized in a wide variety of products including, but not limited to, crude, diesel, jet, gasoline, lube oil, benzene, hexane, boiler feedwater, and chemicals. Of course, the owner/user needs to conduct a review of safe operating procedures prior to performing robotic inspection. The robotic inspection process can acquire a large density of measurements over an analyzed area, which can total hundreds of thousands of ultrasonic thickness measurements. This enables an evaluation using statistical methods to extrapolate the thinnest remaining metal of the entire bottom. Some robotic equipment can also perform adequate inspection on other portions of the tank and accessories (bottom settlement, a visual inspection of the vapor space, and a visual inspection of the tank bottom).

Figure A.1—Automatic UT

Figure A.2—MFL Scanner

Figure A.3—UT Scrub

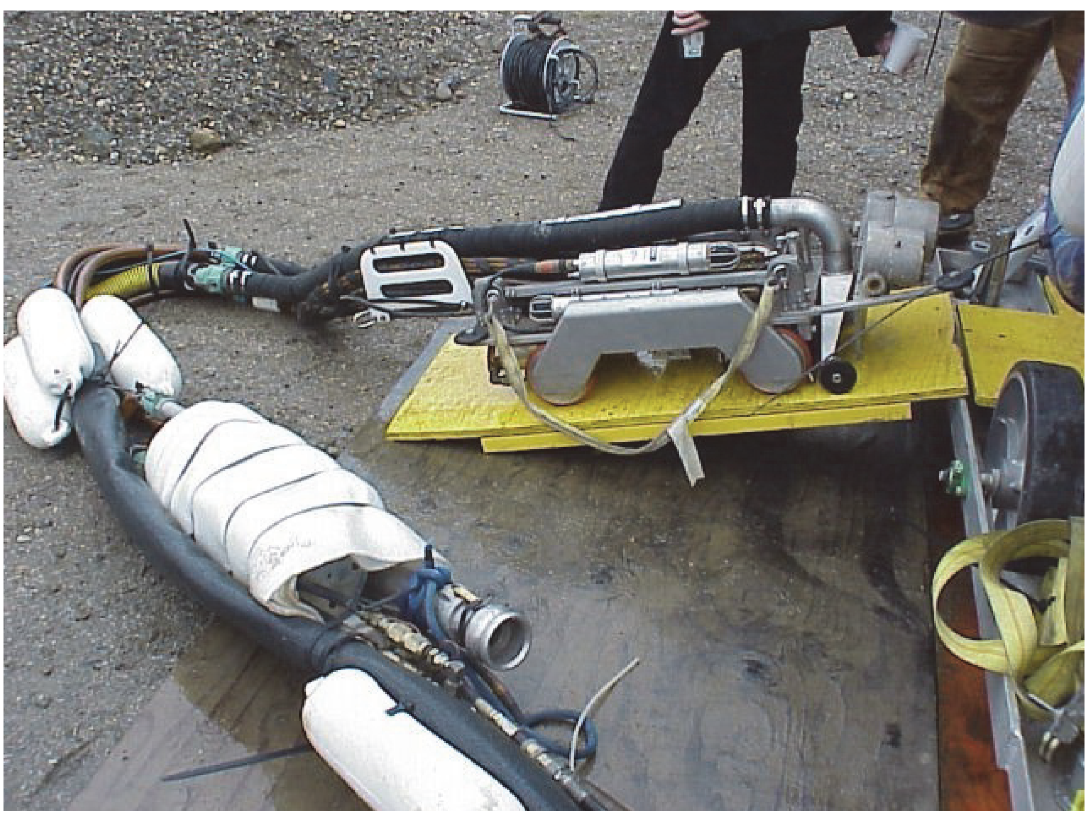


Figure A.4—Robotic Inspection Tool

Annex B
(normative)

Similar Service Evaluation Tables

Table B.1—Selected Factors for Using Similar Service Principles in Estimating Corrosion Rates for Tank Bottoms

Factor	Range	Comment
Product Side		
Stock	Can range from nil to very high rates; corrosion can be in form of pitting or general thinning or both.	Hydrocarbon stocks typically result in corrosion rates of 1 mil to 3 mils (0.025 mm to 0.076 mm) per year for finished fuels. Aviation gas may be 2 to 3 times this amount. Crude oils have variable rates of corrosion. It is important to apply similar service to similar stocks, preferably the same stock, unless it can be demonstrated that the extrapolation of corrosion rate from one stock to another is warranted.
Temperature	Stock temperatures can be divided into two cases: (1) ambient or tanks and (2) heated or refrigerated tanks. Most petroleum tanks are ambient temperature. For heated tanks, most are below 500 ºF (260 ºC). Asphalt tanks are typically the highest temperatures and are typically at about 500 ºF (260 ºC). Refrigerated tanks vary from ambient down to cryogenic temperatures.	Temperature is a critical factor when using similar service because reaction rates typically double for every 18 ºF (10 ºC) increase in temperature. This increase due to higher temperature also applies to corrosion rates. For ambient tanks, note that tank location will impact ambient storage temperature to a degree.
Water bottoms	Some tanks have no water bottoms (e.g. asphalt tanks or lube oil tanks); other tanks have very aggressive water bottoms such as crude oil tanks; finished fuel oil tanks may have water bottoms but the corrosion rates can be variable.	In general, petroleum tanks do not have water bottoms. For tanks with water bottoms, internal tank bottom corrosion rates may be primarily controlled by the chemical composition of the water bottoms and basic factors such as pH. Application of similar service for tanks with water bottoms should be based on product produced by the same or a similar manufacturing plant or process if the water chemistry of the water bottoms is not known.
Bottom design	The design of the tank bottom will impact the ability to remove all water bottoms or other phases and debris that can rest on the bottom and accelerate corrosion. Bottoms range from flat, to cone up, cone down, or single slope. The slope itself can vary. The use of a foundation and ringwall will impact the long-term ability of the tank bottom to retain the design drainage patterns.	It should be realized that even if water is removed regularly and the tank is designed for water removal, depending on the quality of the tank bottom and the design, some water cannot be removed. In this case, the tank essentially carries a water bottom and the use of similar service should assume that there is a water bottom.
Internal lining	Ranges from unlined to fully lined. Linings range from a thin-film to a reinforced thick-film. The general classifications of linings are thin-film, thick-film and reinforced thick-film. The selection for the lining system is dependent upon the product being stored, temperature of operation and the condition of the tank.	Linings are used to prevent corrosion from occurring and are applied to the areas of a tank that are susceptible to corrosion. The areas of the tank that are commonly lined are: the tank bottom and 2 ft to 3 ft (61 cm to 91 cm) up the shell; the roof and down the shell to the liquid level; and local bands of the shell at the liquid vapor interface. In addition, some tanks are fully lined to prevent corrosion and to improve product quality Effective linings can reduce product side corrosion. Factors that increase the life of a properly selected lining system are outlined in API 652. If factors (e.g. material selection, surface preparation, application among others) are not properly performed they can reduce the effectiveness of the lining and projected life of the coating.

Table B.1—Selected Factors for Using Similar Service Principles in Estimating Corrosion Rates for Tank Bottoms (Continued)

Factor	Range	Comment
Cathodic protection (CP)	Typically only applied to crude oil tanks. For crude tanks, ranges from no CP to CP applied to the bottom. Coating efficiency is a factor that addresses how much of the coating is actually effective. CP applied internally (sacrificial) to uncoated tanks is possible, but limited to small tanks and short design life.	Use of similar service involves consideration of the life of the CP system as well as its effectiveness and whether the tank is, or is not coated.
Soil Side		
Foundation material	Concrete ringwall, concrete slab, engineered fill, native soil.	Concrete is alkaline and tends to reduce corrosion rates as compared to typical soil. Since soil and fill corrosion rates are site specific, similar service should be limited to experience with the same site or sites with higher corrosion rates.
Release prevention barrier (RPB)	Double bottoms, plastic liner under tanks, lined secondary containment.	Tanks with double bottoms have the new bottom elevated at least 4 in. (10 cm) above the old bottom and therefore standing water corrosion is reduced. Tanks that have RPBs or liners installed under and around the tank bottoms are more likely to trap water and thus increase corrosion. Similar service must consider the impact of standing water and drainage that results from use of RPBs.
Drainage	Poor, stagnant to well drained.	Drainage is impacted by foundation design, native soil, RPBs, and by original design for drainage.
Isolation from old bottom	Isolated not-isolated. Isolation means electrical insulation of the old bottom to the new bottom by use of a non-conductive membrane. Since new steel is anodic (more corrosive) than old steel, many improperly installed double bottoms are subject to a corrosion life for the new bottom which is shorter than that of the original old bottom.	Similar service must be based on knowledge of whether the tank being compared has a double bottom which is isolated or not.
Cathodic protection (CP)	CP systems for tank bottoms can be galvanic or impressed current. Impressed current systems have an indefinite life, but must be maintained. Galvanic or sacrificial systems do not need to be maintained, but have a finite life. Either type of system can be improperly or ineffectually installed.	Use of similar service should only be applied to cathodic protection systems of the same kind (i.e. galvanic, impressed current). Additional considerations apply primarily to verification that the CP system is effective.

Table B.2—Similar Service Example for Product-side Corrosion

Product Side	Variable		Corrosion Characteristics
	Existing Tank	New Tank	
Stored liquid	Gasoline	Gasoline	Same
Temperature	Ambient	Ambient	Same—based on same location. Note if similar service is being used for different locations then the average ambient temperature difference should be evaluated to see if it is important in the similar service analysis; typically it will not be unless the temperature difference is greater than 10 °F (5.5 °C).
Water bottoms	None	None	Same—weekly water draws are performed to ensure that water bottoms are removed; in addition, a water-sensing probe is installed in the tank bottom to ensure that water does not exist.
Bottom design	Cone-up	Shovel bottom	Same—both bottom designs are sloped to remove water.
Internal coating	Not coated	Bottom and up 2 ft (61 cm) on shell coated.	Conservative—new design will be more conservative than old; therefore, corrosion rate will be less than the old tank.
Cathodic protection	No CP	No CP	Same

Annex C
(normative)

Qualification of Tank Bottom Examination Procedures and Personnel

C.1 Introduction

C.1.1 This Annex provides guidance for qualifying both tank bottom examination procedures and individuals that perform tank bottom UT prove-up examinations. Owner-operators may elect to either apply this Annex as written or modify it to meet their own applications and needs. Tank bottom examinations are an important factor in providing the owner-operator increased assurance of tank integrity. As a result, it is important that qualified examination procedures and personnel are used in these examinations. Specific agreements and requirements for qualification of tank bottom examination procedures and tank bottom examiners should be established between the owner-operator and the Authorized Inspection Agency.

C.1.2 There have been many NDE tools developed for inspecting tank bottoms. Most of these tools are complex and require the operator to have a high level of knowledge and skill. The effectiveness of these examinations may vary greatly depending on the equipment used, the examination procedure, and the skill of the examiner.

Often the owner-operator will not have the ability to easily determine if the tank bottom examination has been effective in assessing the actual condition of the tank bottom. The requirements in this Annex will provide the owner-operator additional assurance that the tank bottom examination will find significant metal loss.

C.2 Definitions

C.2.1
essential variables
Variables in the procedure that cannot be changed without the procedure and scanning operators being requalified.

C.2.2
examiners
Scanning operators and NDE technicians who prove-up bottom indications.

C.2.3
bottom scan
The use of equipment over large portions of the tank bottom to detect corrosion in a tank bottom. One common type of bottom-scanning equipment is the Magnetic Flux Leakage (MFL) scanner.

C.2.4
authorized inspection agency
The company that performs the tank bottom examination.

C.2.5
non-essential variables
variables in the procedure that can be changed without having to requalify the procedure and/or scanning operators.

C.2.6
qualification test
The demonstration test that is used to prove that a procedure or examiner can successfully find and prove-up tank bottom metal loss.

C.2.7
scanning operator or operator
The individual that operates bottom-scanning equipment.

C.2.8
sizing or prove-up
Activity that is used to accurately determine the remaining bottom thickness in areas where indications are found by the bottom scanning equipment. This is often accomplished using the UT method.

C.2.9
tank bottom examination
Examination of a tank bottom using special equipment to determine the remaining thickness of the tank bottom. It includes both the detection and prove-up of the indications. It does not include the visual examination that is included in the internal inspection.

C.2.10
tank bottom examination procedure
TBP
A qualified written procedure that addresses the essential and non-essential variables for the tank bottom examination. The procedure can include multiple methods and tools, i.e. bottom scanner, hand scanner, and UT prove-up.

C.2.11
tank bottom examiner qualification record
TBEQ
A record of the qualification test for a specific scanning operator. This record must contain the data for all essential variables and the results of the qualification test.

C.2.12
tank bottom procedure qualification record
TBPQ
A record of the qualification test for a tank bottom examination procedure. This record must contain the data for all essential variables and the results of the qualification test.

C.2.13
variables or procedure variables
Specific data in a procedure that provides direction and limitations to the scanning operator. Examples include; plate thickness, overlap of adjacent bottom scans, scanning speed, equipment settings, etc.

C.3 Tank Bottom Examination Procedures

C.3.1 Each Authorized Inspection Agency performing tank bottom examinations is responsible to have and use Tank Bottom Examination Procedure(s) (TBP). These procedures provide direction for examiners performing tank bottom examinations. A procedure also allows the owner-operator or Authorized Inspector to verify whether the examiners are correctly performing the examinations.

C.3.2 The Authorized Inspection Agency that performs the tank bottom examinations should develop the Tank Bottom Examination Procedures (TBP).

C.3.3 Each TBP should address essential and non-essential variables. Section C.5.4 provides guidance for determining appropriate TBP essential and non-essential variables. Each procedure should specify limits on appropriate variables, e.g. plate thickness range.

C.4 Tank Bottom Examiners

C.4.1 Examiners need only to be qualified for the work they do in the field. For example, scanning operators who only use the bottom scanning equipment and do not prove-up the flaw with a follow-up method need only to be qualified for the scanning operation.

C.4.2 The purpose of qualifying the tank bottom examiner is to determine that the examiner is capable of satisfactorily using a qualified procedure to determine the condition of the tank bottom.

C.4.3 Each Authorized Inspection Agency is responsible to train, test and qualify the scanning operators and examiners they employ using follow-up techniques. Qualifications gained through one Authorized Inspection Agency are not necessarily valid for any other Authorized Inspection Agency (see C.4.4 and C.4.9.f).

C.4.4 The Authorized Inspection Agency is responsible to train each scanning operator they employ. Each scanning operator should receive a minimum of 40 hours of training. This training should include:

Instruction on the NDE principles/methods used by the bottom scanner, limitations and application of the specific scanning equipment and procedure, scanning equipment calibration and operation, key scanning equipment operating variables, etc.

Hands-on operation of the bottom scanner under the direct supervision of a qualified scanning examiner.

When hiring experienced examiners, The Authorized Inspection Agency should verify and document previous examiner training and provide any necessary additional training experienced examiners should be provided training regarding specific procedural requirements and test equipment to be utilized by the new employer.

C.4.5 The Authorized Inspection Agency is responsible to test each scanning operator by written examination. The test questions should be appropriate for the scanning method to be used. The test should include a minimum of 40 questions. The Authorized Inspection Agency should establish the passing score for the written examination.

C.4.6 The Authorized Inspection Agency is responsible to qualify all examiners they employ. All examiners (scanning operators and examiners performing prove-up on the indications) should be qualified by performing an examination on test plates as specified in C.5. Only third-party companies, having no conflict of interest in tank bottom examination applications, or owner-operator companies may facilitate qualification tests. The examiner should be considered qualified if the acceptance criteria specified in C.5.3 has been met.

Examiners performing prove-up of indications using Ultrasonic Testing methods should be qualified in accordance with API 650 and supplemental requirements given in this Annex.

C.4.7 During the qualification test, a Tank Bottom Examiner Qualification record (TBEQ) must be completed for each examiner. The TBEQ is a record of the variables used during the qualification test. On the TBEQ, the qualifying company must record:

a) the essential variables from the qualification test;

b) the qualification test results;

c) number of hours the individual has been trained;

d) test score from the written training examination.

The TBEQ should be certified (signed) as accurate by a representative of the Authorized Inspection Agency and a representative of the company facilitating the test.

C.4.8 The TBEQ may be written in any format that contains all the required information.

C.4.9 The bottom-scanning examiners (operators and/or UT examiners) should be requalified when any of the following apply:

a) When the examiner is not qualified to the TBP that is to be used at the owner-operator facility.

b) When the Authorized Inspection Agency changes the TBP and that change requires the procedure to be requalified.

c) When the operator has not performed a tank bottom scan in 6 months.

d) When the operator has not used the specific procedure (TBP) for 12 months.

e) When the Authorized Inspection Agency has reason to question the ability of the examiner.

f) When an examiner changes to a new employing Authorized Inspection Agency that utilizes procedures with essential variables that are different from the previous employer's procedures.

C.5 Qualification Testing

C.5.1 Qualification Test Plates

C.5.1.1 The qualification test will be performed on a test tank bottom with designed flaws. The test tank bottom should be of sufficient size to provide space for the designed flaws (a minimum of 70 ft^2 (6.51 m^2)). The plate material used to fabricate test plates may be either new steel or used steel. It should be noted that the results obtained during qualification tests might not be indicative of the results of examinations performed on other plates of differing quality or permeability.

When used steel is utilized for qualification purposes, the qualification test acceptance standards recommended in C.5.2 may not be appropriate. The owner-operator should establish its own acceptance standards in such cases.

C.5.1.2 The *minimum* number and types of underside test pits located on the test plates are described below:

Remaining Bottom Thickness (*t*)	Minimum # of Pits
t < 0.050 in. (1.27 mm)	2
0.050 < t < $^1/_2\ T$	5
$^1/_2\ T < t < {}^2/_3\ T$	4

Key: T = nominal bottom thickness; t = remaining bottom thickness at test plate flaws.

NOTE Test pits should generally be hemispherical having a depth-to-diameter ratio of from 20 % to 50 %. Test pits should not be flat bottom holes since examiners may interpret these as a lamination. Also machined conical holes should not be used since they are difficult to size with UT methods.

The owner-operator may consider placing additional flaws near the plate edge, i.e., less than 6 in. (0.15 m) from the edge, to determine if such flaws can be detected by Authorized Inspection Agency procedures. Any flaws placed closer than 6 in. (0.15 m) to the plate edge should be in addition to those shown above and should not be included in determining qualification unless specifically required by an owner-operator and such defects are stated as being detectable in Authorized Inspection Agency procedures.

C.5.1.3 The minimum number and types of product side test pits located on the test plates are described below:

Remaining Bottom Thickness (t)	Minimum # of Pits
0.050 in. (1.27 mm) < t < $^1/_2\ T$	2
$^1/_2\ T < t < {}^2/_3\ T$	2

C.5.1.4 There should also be at least one area representing general soil side corrosion. This area should be at least 10 in.^{2} (64.52 cm^2) and have a remaining bottom thickness of about $^1/_2\ T$ (nominal plate thickness).

C.5.2 Qualification Test Acceptance Standards

C.5.2.1 The following acceptance criteria must be met when qualifying either an examination procedure or an examiner. If all the acceptance criteria are met, the procedure or examiner should be considered qualified. Owner-operators may substitute alternative acceptance criteria, either more or less conservative, based on their specific needs and requirements.

C.5.2.2 When qualifying either a procedure or a scanning operator, the operator must be able to *detect* the following flaws:

Remaining bottom thickness (t)	Minimum Level of Flaw Detection
t < 0.050 in. (1.27 mm)	90
0.050 in. < t < $^1/_2\ T$	70
$^1/_2\ T < t < {}^2/_3\ T$	40
Area of general corrosion	100 %

C.5.2.3 When qualifying either a procedure or an examiner, who proves up the indications, the examiner must be able to determine the flaw depth as follows:

Type of Tank Bottom	Prove-up (flaw depth)
Not coated	±0.020 in. (0.51 mm)
Thin coating < 0.030 in. (0.76 mm)	±0.030 in. (0.76 mm)
Thick coatings > 0.030 in. (0.76 mm)	Per agreement with owner-operator

The owner-operator should determine if additional flaw dimensions need to be addressed in the qualification process.

C.5.2.4 While false calls, also referred to as over-calls, tend to be more of an examination efficiency issue than a tank bottom integrity issue, the owner-operator should determine if they should be addressed in the qualification process.

C.5.3 Qualification Test Variables

C.5.3.1 Essential Variables are those items that may have a significant effect on the quality of the examination if they are changed from those used during the qualification test.

C.5.3.2 Table C.1 lists suggested items that may be considered as essential variables for the qualification test when qualifying either a tank bottom examination procedure or a tank bottom examiner. Essential variables may be different for different types of tank bottom scanners. Authorized Inspection Agencies are responsible to determine what additional variables should be considered essential variables for each tank bottom scanner.

Table C.1—Suggested Items that May Be Considered as Essential Variables for the Qualification Test

Essential Variable	Used during Test	Qualified
Scanner Equipment	As tested	Same as tested
Prove-up Equipment	As tested	Same as tested
Prove-up Procedure	As tested	Same as tested
Plate Thickness (T)	T	T +0.050 in. (1.27 mm) / –0.130 in. (3.30 mm)
Coating Thickness (t_c)	t_c = 0.000 in. (0.0 mm)	0.000 in. (0.0 mm)
	0.008 in. (0.20 mm) < $t_c \leq$0.030 in. (0.76 mm)	0.001 in. (0.03 mm) – 0.030 in. (0.76 mm)
	0.030 in. (0.76 mm) < t_c< 0.080 in. (2.0 mm)	0.030 in. (0.76 mm) – 0.080 in. (2.0 mm)
	$t_c \geq$ 0.080 (2.0 mm)	0.080 in. (2.0 mm) – t_c
Distance from Shell (d_s)	d_s	lesser of 8 in. (203 mm) or d_s
Critical Equipment Settings	As tested	Per Manufacturer
Threshold Settings (T_h)	T_h	< 10 % T_h
Calibration or Functional Check		Same as tested

C.5.3.3 Essential variables and the values must be recorded on the TBP and on the TBEQ.

C.5.3.4 Non-essential Variables are those items that will have a lesser affect on the quality of the examination. Non-essential variables may be different for different types of tank bottom scanners.

C.5.3.5 Non-essential variables must be listed on the TBP but need not be addressed on the TBPQ or the TBEQ. The following is a list of examples of items that might be considered as non-essential variables. Equipment manufacturers and Authorized Inspection Agencies are responsible to determine what addition factors should be considered non-essential variables for each tank bottom scanner:

a) scanner speed;

b) scanning pattern;

c) height limitations;

d) overlap between scans;

e) plate cleanliness;

f) non-critical equipment settings.

NOTE Some of the listed non-essential variables may actually be essential variables for specific types of scanners.

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